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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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IN THE MATTER OF THE JOINT APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC., SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. AND MOHAVE ELECTRIC COOPERATIVE, INC. FOR APPROVAL OF (1) A PARTIAL-REQUIREMENTS AGREEMENT WITH SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC., (2) AN AMENDMENT TO THE PARTIAL-REQUIREMENTS AGREEMENT WITH MOHAVE ELECTRIC COOPERATIVE, INC. AND (3) REVISED PARTIAL-REQUIREMENTS RATES IN RELATION THERETO	Doc **E-01773A-07-0490** **E-01575A-07-0490** **E-01750A-07-0490** **JOINT APPLICATION**

Arizona Corporation Commission
DOCKETED
AUG 22 2007
DOCKETED BY

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The Arizona Electric Power Cooperative, Inc. ("AEPCO"), Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") and Mohave Electric Cooperative, Inc. ("MEC") (collectively, the "Applicants") submit this Joint Application for approval of a new Partial-Requirements Capacity and Energy Agreement between AEPCO and SSVEC, an Amendment to the Partial-Requirements Agreement between AEPCO and MEC and a revised Partial-Requirements Rates and Fixed Charge Schedule in relation thereto.

In support of their Application, the Applicants state as follows:

1. AEPCO is an Arizona non-profit electric generation cooperative which supplies all or most of the power and energy needs of its five Arizona Class A member distribution cooperatives. Currently, AEPCO's Arizona all-requirements members are the Duncan Valley

Electric Cooperative, Graham County Electric Cooperative, Trico Electric Cooperative and SSVEC. Under the all-requirements relationship, these Class A members are obligated to purchase, and correspondingly AEPCO is obligated to plan for and supply, all of the power and energy needs which these distribution cooperatives require for their retail members.

2. MEC is currently AEPCO's only partial-requirements Class A member. In Decision No. 63868 dated July 25, 2001, the Commission approved the Partial-Requirements Capacity and Energy Agreement between AEPCO and MEC as part of AEPCO's restructuring (the "MEC Partial"). Under the partial-requirements relationship, MEC commits to purchase a fixed amount of capacity and energy from AEPCO and then secures from a source of its choosing any additional power requirements necessary to meet the power and energy needs of its retail members.

3. One of the primary objectives of the AEPCO restructuring was to provide its Class A members with more flexible purchased power arrangements. The Conversion Agreement executed as part of the restructuring provides that any of the members have the right to elect conversion from an all- to a partial-requirements status as MEC did following the four-year member study process which led to AEPCO's 2001 restructuring.

4. SSVEC has elected to convert its Class A member relationship with AEPCO from an all- to a partial-requirements relationship. Attached hereto as Exhibit A is the Partial-Requirements Capacity and Energy Agreement between AEPCO and SSVEC and its Master Amendment (the "SSVEC Partial"). AEPCO's Board, which is comprised of elected representatives of its members, has reviewed, approved and supports the SSVEC Partial. The Board also instructed AEPCO's management to secure necessary regulatory consents to authorize its implementation.

5. In that regard, SSVEC's conversion to partial-requirements status is also subject to the review and approval of the Rural Utilities Service ("RUS"). By letter dated June 7, 2007, the RUS notified AEPCO of its approval of the SSVEC Partial. Attached as Exhibit B is a copy of the correspondence.

6. The SSVEC Partial differs in certain respects from the MEC Partial which is currently in effect and which the Commission approved in Decision No. 63868. In order to assure uniformity among similarly situated members, attached as Exhibit C is the Second Amendment to the MEC Partial and its Master Amendment ("MEC Partial Amendment"). As reflected in Exhibit B, the RUS has also approved the MEC Partial Amendment. Primarily, the MEC Partial Amendment revises the MEC Partial to (a) add provisions necessary to recognize that SSVEC will be a second partial-requirements member, (b) adopt some corrections discovered during the SSVEC contracting process and (c) adjust for changes made in the SSVEC Partial. Key provisions of the MEC Partial Amendment are summarized in the attached Exhibit D.

7. Attached as Exhibit E is a form of revised Partial-Requirements Schedule. The base rates proposed for SSVEC are the Phase 3 rates authorized for implementation on September 1, 2007. Depending upon the timing of Commission action on this Application, this form may require further adjustment to reflect rates then in effect.

8. SSVEC will be charged the same O&M and energy rates which MEC is charged and which were authorized by the Commission in AEPCO's last rate decision – Decision No. 68071 dated August 17, 2005 (the "Decision"). SSVEC's fixed charge of $757,429 per month is based upon the same method authorized in the Decision but differs arithmetically because SSVEC has a lower Allocated Capacity Percentage than MEC (31.7% for SSVEC v.

35.8% for MEC). No revisions to the rates charged to AEPCO's remaining all-requirements members or MEC are necessary as a result of SSVEC's partial-requirements conversion.

9. SSVEC's fuel and purchased power base cost will also be the same as MEC's – $0.01603/kwh. As for the FPPCA adjustor rate, Applicants propose that SSVEC continue to use the all-requirements adjustor rate in effect at the time this Application is approved. AEPCO will then devise an FPPCA adjustor rate for SSVEC at the time of the first semi-annual adjustment following approval.

10. Based upon 2006 operating experience, the revised SSVEC partial-requirements rates produce approximately $2 million less in revenues than the revenues AEPCO derives from current rates. Adjusting, however, for the final step increase taking effect September 1, 2007, AEPCO's TIER and DSC coverages meet and exceed mortgage requirements. Attached as Exhibit F are schedules: (a) summarizing the present and proposed rates, (b) setting forth rate base and rate of return data and (c) summarizing rate base and results of operations for the year ended December 31, 2006.

11. In order to allow SSVEC promptly to commence planning and procurement for the summer of 2008 as well as to afford AEPCO the full 2008 calendar year of operating experience with SSVEC as a partial-requirements member (Decision, p. 16, Fourth Ordering Paragraph), the Applicants request that the Commission approve this Application no later than its December 2007 Open Meeting.

WHEREFORE, having stated their Joint Application, Applicants request that the Commission enter its Order approving the following without a hearing:

1. The SSVEC Partial Agreement attached as Exhibit A;

2. The Second Amendment to the MEC Partial Agreement attached as Exhibit C;

3. The revised Partial-Requirements Members Rates and Fixed Charge Schedule in a form similar to that attached as Exhibit E; and

4. Continued use of the all-requirements FPPCA adjustor rate for SSVEC in effect at the time of approval until the first semi-annual FPPCA adjustor is recalculated following approval.

RESPECTFULLY SUBMITTED this 22nd day of August, 2007.

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Original and 17 copies filed this 22nd day of August, 2007, with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Copies of the foregoing delivered this 22nd day of August, 2007, to:

Commissioner Mike Gleason, Chairman
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Phoenix, Arizona 85007

Commissioner William A. Mundell
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EXHIBIT A

EXECUTION FINAL

PARTIAL REQUIREMENTS

CAPACITY AND ENERGY AGREEMENT

BETWEEN

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

AND

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.

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PARTIAL REQUIREMENTS
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PARTIES

The Parties to this PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT (Agreement or SSVEC Partial Requirements Capacity and Energy Agreement) are Sulphur Springs Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized under the laws of the State of Arizona (Member or SSVEC), and Arizona Electric Power Cooperative, Inc. (AEPCO), a non-profit corporation as defined and organized under the generation and transmission electric cooperative laws of the State of Arizona. Member and AEPCO are referred to in this Agreement individually as "Party" and collectively as "Parties."

RECITALS

A. AEPCO and the Member are parties to that certain Wholesale Power Contract, dated as of February 15, 1962, as amended, (Existing Wholesale Power Contract).

B. AEPCO's membership consists of Class A Members, Class B Members and Class C Members. AEPCO's Class A Members, as of the Agreement Date, consist of Anza Electric Cooperative, Inc. (ANZA); Duncan Valley Electric Cooperative, Inc. (DVEC); Graham County Electric Cooperative, Inc. (GCEC); Mohave Electric Cooperative, Inc. (MEC); Trico Electric Cooperative, Inc. (TRICO) and Member, which members are referred to individually and collectively in this Agreement as "Class A Member(s)." The Class B Member of AEPCO, as of the Agreement Date, is the City of Mesa. The sole Class C Member of AEPCO, as of the Agreement Date, is the Salt River Project Agricultural Improvement and Power District. The Class A, B and C Members are referred to in this Agreement collectively as "Members." The Class A Members, except MEC and Member, are referred to in this Agreement collectively as "All Requirements Members," and individually as an "All Requirements Member." Member and MEC are referred to in this Agreement collectively as "Partial Requirements Members," and individually as a "Partial Requirements Member."

C. AEPCO's Class A Members, including the Member, are electric cooperative non-profit membership corporations or non-profit corporations conducting business in the States of Arizona, New Mexico and California. Each Class A Member originally joined with the other Class A Members, either to form AEPCO, or to join in AEPCO's operations pursuant to an all-requirements agreement with AEPCO similar to the Existing Wholesale Power Contract. The Parties are executing this Agreement contemporaneously with the execution of a Transmission Agreement between Southwest Transmission Electric Power Cooperative, Inc., a non-profit corporation organized under the electric power generation and transmission cooperative corporation laws of the State of Arizona (TRANSCO) and Member; and of a Resource Integration Agreement as amended as of the Agreement Date, concerning the pooling and operation of certain Resources. Further, TRANSCO and the Member may also contemporaneously execute other transmission agreements between them.

D. As part of the overall restructuring of its system, AEPCO transferred its Transmission Business substantially as an entirety to TRANSCO. AEPCO also transferred its CSP Business substantially as an entirety to Sierra Southwest Electric Power Cooperative Services, Inc. (CSP), a non-profit corporation organized under the electric power generation and transmission cooperative corporation laws of the State of Arizona. Such restructuring of AEPCO was accomplished pursuant to the provisions of the Restructuring Agreement, dated October 11, 2000, entered into by and among AEPCO, TRANSCO and CSP (Restructuring Agreement), and the Member Agreement, dated July 2, 2001, entered into by and among AEPCO, TRANSCO, CSP and the Class A Members (Member Agreement). Also, as part of the restructuring, AEPCO and MEC entered into a Partial Requirements Capacity and Energy Agreement, dated August 1, 2001 (MEC Partial Requirements Capacity and Energy Agreement), and ANZA, DVEC, GCEC, SSVEC, TRICO and AEPCO entered into the Conversion Agreement, dated August 1, 2001, (Conversion Agreement).

E. AEPCO, as of the Agreement Date, owns and operates electric generation facilities and assets and has rights to electric energy and capacity under various purchase agreements (collectively, the "Existing Resources").

F. AEPCO has obligations for loans which, in whole or in part, financed the construction of generation and transmission facilities, all of which are evidenced by mortgage notes (collectively, the "AEPCO Notes") payable to or guaranteed by the United States of America (Government), acting through the Rural Utilities Service (RUS), as successor to the Rural Electrification Administration, and the National Rural Utilities Cooperative Finance Corporation (CFC), and loans made by, or securities issued to, or obligations undertaken to others, including the trustees and bond holders of the Pollution Control Revenue Refunding Bonds (Pooled Series 1997C), the Solid Waste Disposal Revenue Bonds (Pooled Series 1994A), and the Central Bank for Cooperatives (collectively, the "Financial Entities"). In the future, AEPCO may refinance such existing loans through new loans which will also be included in the "AEPCO Notes," as used in this Agreement.

G. The AEPCO Notes and certain of the loans made by, or securities issued to, or obligations undertaken to others (collectively, with the AEPCO Notes, the "Secured Obligations") are secured by a certain Consolidated Mortgage and Security Agreement dated as of June 14, 1989, made by and among AEPCO and RUS and CFC as amended and consolidated, supplemented or restated from time to time (the "AEPCO Mortgage").

H. This Agreement and the obligations hereunder and payments due to AEPCO under this Agreement are pledged and assigned to secure the Secured Obligations as provided in the AEPCO Mortgage.

I. RUS, CFC and the other holders of the Secured Obligations are relying on this Agreement and the obligations hereunder, the MEC Partial Requirements Capacity and Energy Agreement and the Existing Wholesale Power Contracts, and the obligations thereunder, to ensure the repayment of the Secured Obligations and to fulfill the purposes of the REAct. AEPCO and the Member, by executing this Agreement, acknowledge such reliance and agree that RUS is a third party beneficiary of this Agreement and that this Agreement also operates for the benefit of RUS.

J. AEPCO and the Member recognize that the Existing Resources and transmission assets initially constructed or subsequently acquired and placed in service by AEPCO have served, on an integrated basis, the full electric requirements of AEPCO's All Requirements Class A Members, including the Member, and the partial requirements of MEC and other wholesale customers of AEPCO. Commencing on the Agreement Date, the servicing of the current and future electric loads of AEPCO, CSP, MEC and the Member will be managed pursuant to the Resource Integration Agreement, as amended as of the Agreement Date, between CSP, AEPCO, TRANSCO, MEC and Member; the Transmission Agreements between TRANSCO and Member and TRANSCO and MEC; certain agreements for transmission service between TRANSCO, the All Requirements Members and AEPCO, pertaining to the electric loads of the All Requirements Members; other arrangements for transmission service between AEPCO and TRANSCO pertaining to the electric loads of other wholesale customers of AEPCO; and arrangements for transmission service between TRANSCO and CSP, pertaining to the electric loads of CSP.

K. The Member has determined that its interests and the interests of its consumers will be best served by electing to become a Partial Requirements Member pursuant to the Conversion Agreement and by purchasing electric energy and capacity from AEPCO pursuant to the terms and conditions of this Agreement.

L. The Member agrees to purchase from AEPCO, and AEPCO agrees to sell to the Member, electric capacity, based upon the Allocated Capacity Percentage (the "ACP") of Member, and associated energy during the term of this Agreement on the terms and conditions herein set forth.

AGREEMENT

NOW, THEREFORE, in consideration of the premises and the mutual undertakings contained herein, the Parties agree as follows:

1. <u>DEFINITIONS</u>:

All capitalized terms used and defined herein shall have the meaning set forth in this Section 1, and are defined solely for use with this Agreement, including Rate Schedule A and Schedule B hereto. All capitalized terms used and not defined herein shall have the respective meanings as set forth in Amended and Restated Appendix A.

1.1 "AEPCO's Member Peak Demand" shall mean the highest thirty (30) minute integrated demand in kW experienced during the billing period of the aggregate demands of all Class A Members purchased pursuant to this Agreement, the MEC Partial Requirements Capacity and Energy Agreement and the Existing Wholesale Power Contracts.

1.2 "AEPCO's Revenue Requirement" shall mean the total revenues, from any source whatsoever, necessary to enable AEPCO, utilizing a twelve month test period to: (i) meet all its anticipated fixed, variable, fuel, and all other costs, obligations and expenses and payments (including all payments on account of Indebtedness of AEPCO); (ii) establish and maintain reasonable financial reserves; and, (iii) include appropriate levels of margins and working capital to satisfy, at a minimum, applicable prescribed annual coverage ratios or any other financial covenants or tests imposed by the Financial Entities, as may exist from time to time, determined in accordance with Accounting Requirements.

1.3 "AEPCO's Revenue Requirement From AEPCO Class A Members" shall mean AEPCO's Revenue Requirement less revenues anticipated to be received by AEPCO from all sources other than the AEPCO Class A Members.

1.4 "AEPCO's Revenue Requirement From Partial Requirements Members" shall mean that portion of AEPCO's Revenue Requirement From AEPCO Class A Members allocated to Partial Requirements Members in accordance with Section 5 herein and Section 3 of Rate Schedule A.

1.5 "Demand Overrun Adjustments" shall have the meaning set forth in Section 2.2 of Rate Schedule A.

1.6 "Fixed Charge" shall mean the charge computed in accordance with Sections 5.2 and 5.3 herein which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

1.7 "Long Term Debt" shall have the meaning given in accordance with Accounting Requirements.

1.8 "MEC Partial Requirements Capacity and Energy Agreement" shall mean the Partial Requirements Capacity and Energy Agreement, by and between AEPCO and MEC.

1.9 "MEC Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and MEC.

1.10 "Member Billing Demand" shall mean, as to Member, the demand of Member in kW integrated over the thirty (30) minute period occurring coincident in time with the AEPCO Member Peak Demand purchased by Member from AEPCO pursuant to this SSVEC Partial Requirements Capacity and Energy Agreement, which consists of the demands of SSVEC AEPCO Load and SSVEC AEPCO Sales.

1.11 "Member Billing Energy" shall mean the energy in kWh received by SSVEC from AEPCO during the billing period pursuant to this SSVEC Partial Requirements Capacity and Energy Agreement which consists of the energy requirements of SSVEC AEPCO Load and SSVEC AEPCO Sales.

1.12 "PGR Purchase Agreement" shall mean the Power Purchase Agreement between Panda Gila River, L.P., and AEPCO, dated April 15, 2003, as amended.

1.13 "Power Factor Adjustment" shall have the meaning set forth in Section 2.2 of Rate Schedule A.

1.14 "Proposal and Analysis" shall have the meaning set forth in Section 3.4.3 herein.

1.15 "Required Modification" shall have the meaning set forth in Section 3.3.2 herein.

1.16 "SSVEC AEPCO Load" shall mean, the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within the Member's Distribution Service Area of SSVEC (or served from line extensions therefrom) for which SSVEC purchases capacity and energy pursuant to the SSVEC Partial Requirements Capacity and Energy Agreement, but shall not include SSVEC Wheeling Load. Such demand and energy requirements are included within SSVEC Metered kW and SSVEC Metered kWh. The demand component of SSVEC AEPCO Load numerically consists of the coincident aggregate, at a specific time, of: (i) SSVEC Metered kW; less (ii) kW of SSVEC Wheeling Load; less (iii) kW of Member JMP Load of SSVEC; less (iv) kW of CSP JMP Load of SSVEC; (v) less kW of SSVEC Internal Load. The energy component of SSVEC AEPCO Load numerically consists of the aggregate during a specific time interval of: (i) SSVEC Metered kWh; less (ii) kWh of SSVEC Wheeling Load; less (iii) kWh of Member JMP Load of SSVEC; less (iv) kWh of CSP JMP Load of SSVEC; less, (v) kWh of SSVEC Internal Load.

1.17 "SSVEC AEPCO Sales" shall mean the demand and associated energy requirements, including any distribution losses and not including reserves or transmission losses, of those sales of SSVEC to wholesale buyers or to end use loads which are external to Member's Distribution Service Area of SSVEC for which SSVEC purchases capacity and energy pursuant to the SSVEC Partial Requirements Capacity and

Energy Agreement. The demand and energy requirements of SSVEC AEPCO Sales shall be metered (or determined) as agreed between SSVEC and TRANSCO, on the basis of actual capacity and energy supplied at the applicable points of delivery.

1.18 "SSVEC Metered kW" shall mean the demand in kW received at the Delivery Points of SSVEC as measured and recorded during the billing period by revenue quality meters installed at or used in conjunction with such Delivery Points. During each billing period, SSVEC Metered kW consists of the integrated demands of: (i) SSVEC AEPCO Load; (ii) SSVEC Wheeling Load; (iii) Member JMP Load of SSVEC; (iv) CSP JMP Load of SSVEC; and (v) SSVEC Internal Load.

1.19 "SSVEC Metered kWh" shall mean the total energy in kWh delivered to the Delivery Points of SSVEC during the billing period, as measured and recorded for such billing period by revenue quality meters installed at or used in conjunction with such Delivery Points. During each billing period, SSVEC Metered kWh consists of the kWh of energy, as measured at the Delivery Points, consumed by: (i) SSVEC AEPCO Load; (ii) SSVEC Wheeling Load; (iii) Member JMP Load of SSVEC; (iv) CSP JMP Load of SSVEC; and, (v) SSVEC Internal Load.

2. PURCHASE, SALE AND PAYMENT OBLIGATIONS:

2.1 Purchase and Sale.

2.1.1 AEPCO shall sell to the Member, and Member shall purchase from AEPCO, electric energy and capacity (at rates set forth in Exhibit A-1 to Rate Schedule A) scheduled by the Member or its scheduling agent, up to the Member's Allocated Capacity (the "AC"), as determined by the ACP of Member as set forth in Appendix A to Exhibit A-5 to Rate Schedule A and the available AEPCO Resources as set forth in Appendix B to Exhibit A-5 to Rate Schedule A, for delivery to the Member at the point or points of delivery in accordance with Section 6 of this Agreement.

2.1.2 The Member shall take and pay, or pay for such electric energy and capacity under the terms and conditions set forth in this Agreement at rates and charges established pursuant to Section 5 of this Agreement and Rate Schedule A. The Member's payment obligations associated with its ACP in any AEPCO Resource allocated in accordance with this Agreement shall survive and continue until all of Member's payment obligations for such AEPCO Resource are paid in full to AEPCO notwithstanding the occurrence of any event, or the taking of any action permitted or contemplated by this Agreement, with respect to such AEPCO Resource, including, without limitation, any event or action described in Section 2.6.

2.1.3 AEPCO shall sell to Member and Member shall purchase from AEPCO levels of energy set forth in Schedule B.

2.2 AEPCO Obligation to Provide Electric Service. In the event that Resources of AEPCO in which the Member has been assigned an ACP and AC are unavailable to deliver electric energy and capacity to which the Member is entitled hereunder, AEPCO shall be responsible for obtaining electric energy and capacity from other sources in order to assure that Member's schedule is met.

2.3 No Dedication of Resources. The establishment of an ACP for the Member with respect to an AEPCO Resource or the sale by AEPCO to the Member of electric energy and capacity under this Agreement shall not constitute: (i) a sale, lease, transfer, dedication, or conveyance of any ownership interest whatsoever in or to any specific AEPCO Resource nor (ii) an entitlement to the electric energy or capacity from any specific AEPCO Resource. AEPCO shall have the sole and unlimited authority, which it may exercise in its sole discretion, to manage, control and operate all of its Resources consistent with AEPCO's obligations to provide electric energy and capacity to the Member pursuant to this Agreement.

2.4 Power Factor on the Resources of AEPCO. The Member shall maintain Power Factor as close to unity as possible. Member shall pay AEPCO a power factor adjustment in accordance with Rate Schedule A in the event that the Power Factor of the Member is not within the limits set forth therein.

2.5 (Left intentionally blank.)

2.6 Member's Unconditional Obligation to Pay.

2.6.1 The Member shall have an unconditional obligation to make all payments to AEPCO required hereunder at the rates and Fixed Charge and on the terms and conditions set forth herein and in Rate Schedule A. The Member shall make all payments of Fixed Charges and of O&M charges and energy charges for capacity and energy provided for under this Agreement, including without limitation, rates and Fixed Charges resulting from all Required Modifications and Minor Resource Modifications, as the case may be, in a timely manner whether or not any of the following conditions, as applicable, occur: (i) electric energy and capacity has been or is being provided to the Member hereunder; (ii) AEPCO Resources or any part thereof are completed, delayed, terminated, available, operable, operating, retired, sold, leased, transferred, or otherwise disposed of; (iii) the construction or operation of the AEPCO Resources or any part thereof is suspended, interrupted, interfered with, abrogated, reduced, curtailed or terminated; (iv) AEPCO is able to purchase or otherwise obtain electric energy and capacity from any other source; (v) any similar contract with another Member of AEPCO is invalidated; or (vi) any other contract between the Member, AEPCO, TRANSCO or CSP is invalidated, in any such case for any reason whatsoever and whether or not due to the conduct, acts or omissions of AEPCO. Payments by the Member hereunder, and the obligation to pay, shall be absolute and unconditional and shall not be subject to any reduction, whether by offset, set-off, recoupment or otherwise, and shall not be conditioned upon performance or limited by any Class A Member under any other wholesale power sales, power purchase or power marketing agreements entered into by AEPCO.

2.6.2 This Section 2.6 shall not be construed to release AEPCO from the performance of any of its obligations established in this Agreement or, except to the extent expressly provided in this Agreement, prevent or restrict the Member from bringing suit for enforcement of, or damages arising from, any rights that it may have against AEPCO under this Agreement or under any provision of Law, and to compel AEPCO to pay any damages awarded by a court of competent jurisdiction as awarded in a final judgment.

2.7 Disputed Bill. In the event that Member disagrees with a bill from AEPCO, the Member shall pay the bill in full within ten (10) days and within five (5) days after such payment provide AEPCO with written notice that the Member disputes the bill and the reasons for such dispute. AEPCO shall notify Member of its response to such written notice within ten (10) days thereafter. If AEPCO agrees with Member, it shall amend the bill to reflect the correction within ten (10) days after AEPCO's agreement and refund the overpayment plus interest from the date paid by the Member to the date of the repayment to the Member at the Contract Rate of Interest. In the event that AEPCO does not agree with the Member, the Authorized Representatives of the Parties shall attempt to resolve the matter through negotiations. In the event that the Authorized Representatives are unable to reach an agreement within forty (40) days after Member's notice of dispute, the Member may refer the matter to binding arbitration or may seek resolution of such dispute in a court of competent jurisdiction.

3. PLANNING AND RESOURCE ALLOCATIONS AND MODIFICATIONS:

3.1 Resource Planning.

3.1.1 AEPCO shall not be responsible for and Member shall not be charged for: (i) bulk power supply planning, or (ii) any Future Resource procurement services (such services, collectively referred to as "Planning Services") for the Member, except pursuant to a separate written agreement for such Planning Services executed by the Member and AEPCO and paid for by Member. If the Member contracts separately to obtain Planning Services from AEPCO, it shall be referred to as a "Planning Contract Member."

3.1.2 Unless and until the Member becomes a Planning Contract Member, performing or obtaining any Planning Services whatsoever shall be the sole responsibility of Member and not of AEPCO.

3.2 Allocated Capacity Percentage.

3.2.1 Allocated Capacity Percentage (ACP). AEPCO shall at all times maintain the Exhibits to Rate Schedule A which identify all AEPCO Resources, and the ACP and AC allocated to the Member and all other Class A Members with respect to each AEPCO Resource, by month, for the original projected useful life or for the contract term of each AEPCO Resource. AEPCO shall at all times also maintain current Tables and Exhibits to Schedule B. AEPCO shall provide copies of any revised Exhibits and Tables to Member at least fifteen (15) business days before such revisions become effective.

3.2.2 Future Resource. Unless the Parties agree by separate written agreement to establish an ACP for Member in a Future Resource, the Member shall not be charged by AEPCO for any costs directly or indirectly resulting from such Future Resource, and shall have no obligation or responsibility for repayment of the costs or charges of such Future Resource.

3.3 Change of Certain Member Obligations.

3.3.1 Subject to Section 5.6 hereof and Section 3 of Rate Schedule A, the Member's obligations shall be subject to certain changes as follows:

3.3.1.1 Except as provided in this Section 3.3.1, AEPCO may not, in the case of a modification of a Resource in which Member has an ACP, without the prior written consent of the Member: (i) determine and modify the AC of Member in an Existing Resource; (ii) otherwise add or modify an Exhibit to Rate Schedule A; or (iii) modify any other provision of this Agreement, each of which might be required as a result of such Resource Modification.

3.3.1.2 AEPCO may, in the case of a Minor Resource Modification, a Required Modification, or a modification made pursuant to Section 3.5 hereof, without the prior written consent of Member determine and modify the AC of Member in an Existing Resource in accordance with this Section 3 and otherwise add or modify Tables and Exhibits to Rate Schedule A and Schedule B as may be required as a result of any such modification.

3.3.1.3 AEPCO may, in the case of a Resource Modification in which Member has elected not to participate, without the prior written consent of the Member, determine and modify the ACP of Member in such Existing Resource and otherwise add or modify Tables and Exhibits to Rate Schedule A and Schedule B as may be required as a result of such Resource Modification to reflect the revised cost responsibility resulting from such Resource Modification.

3.3.2 AEPCO shall undertake from time to time expenditures for Resource Modifications required to comply with any Legal Requirement or as recommended by an engineering analysis that such a proposed modification is necessary for the safe and reliable functioning of the Resource (Engineering Analysis Requirement), both as determined by AEPCO (Required Modification). AEPCO shall submit to the Member written notification of its decision to undertake, and reasons for, a Required Modification within ten (10) business days after such determination by AEPCO. Member may dispute such determination either as to the requirement for the Required Modification or as to the modification proposed, or both. If the Member disputes only the determination that the Required Modification is a Legal Requirement or an Engineering Analysis Requirement, the Member may refer such matter to binding arbitration under the Rules of the American Arbitration Association and substantive law within fifteen (15) business days of its receipt of notice of AEPCO's decision to undertake the Required Modification. If the Member disputes that the modification proposed by AEPCO is cost justified, Member shall, within forty-five (45) days, provide a more cost-effective alternative plan to AEPCO. If AEPCO has not accepted Member's proposed alternative plan in writing within forty-five (45) days of its receipt by AEPCO, Member may within fifteen (15) business days thereafter refer such matter to binding arbitration as set forth above. In the event Member disputes both the requirement for the Required Modification and the modification proposed, Member shall wait until AEPCO has had a forty-five (45) day opportunity to accept Member's alternative plan before referring such questions to arbitration as provided above. The only issues to be decided by arbitration, unless otherwise agreed by the Parties, shall be: (i) whether the proposed Required Modification was necessary to comply with a Legal Requirement or Engineering Analysis Requirement, and/or (ii) whether the Member's alternative plan for the proposed Required Modification was the more cost-effective proposal consistent with Prudent Utility Practice. In the event that the decision rendered in such arbitration is that the Required Modification was necessary to comply with a Legal Requirement or Engineering Analysis Requirement, and the proposed Required Modification was the more cost effective alternative consistent with Prudent Utility Practice to comply with such Legal Requirement or Engineering Analysis Requirement, AEPCO may proceed with the Required Modification and modify the AC of the Member. If the arbitration decision is that the proposed Required Modification was not required to comply with a Legal Requirement or Engineering Analysis Requirement or that the proposed Required Modification was not the more cost-effective alternative consistent with Prudent Utility Practice to comply with such Legal Requirement or Engineering Analysis Requirement, the Member shall not be assessed any of the costs in its rates, charges or adjustments directly related to such Required Modification. The arbitration decision undertaken in accordance with this Section 3.3.2 shall be final and binding on the Parties, and non-appealable. The arbitration decision shall assess to the non-prevailing Party all expenses and costs, of whatsoever nature, including reasonable attorneys and consultants fees and the costs of arbitration, incurred by the prevailing Party as a result of the arbitration or caused as a consequence of any delay by AEPCO in complying with the Legal Requirement or Engineering Analysis Requirement (if AEPCO is the prevailing Party), and judgment on the award rendered may be entered in any court having jurisdiction thereof. The assessment to such non-prevailing Party shall be paid within thirty (30) days after such arbitration decision is rendered.

3.4 Resource Modifications.

3.4.1 The Member shall have an unconditional obligation to make all payments to AEPCO in accordance with Rate Schedule A to meet the costs, obligations and expenses associated with a decision of AEPCO to undertake a capital expenditure in accordance with this Section 3.4; unless the provisions of Section 3.4.7 apply to Member.

3.4.2 This Section 3.4.2 shall apply to Minor Resource Modifications and Resource Modifications as follows:

(a) Minor Resource Modifications. AEPCO may, in its sole discretion, undertake, from time to time, expenditures for additions, improvements, repairs or modifications to a Generating Resource or modify or extend the term, of a Power Purchase Resource for five (5) years or less which, in either case, shall not: (i) increase the capacity of the AEPCO Resource being modified by greater than ten percent (10%); (ii) result in an increase of greater than five percent (5%) in AEPCO's Revenue Requirement from AEPCO Class A Members upon the operation of such addition, improvement, repair or modification, or extension, as the case may be; or (iii) extend the term of this Agreement. Any expenditure undertaken by AEPCO under this Section 3.4.2(a) shall be a "Minor Resource Modification."

(b) Resource Modifications. AEPCO may propose to undertake, from time to time, Resource Modifications.

3.4.3 Proposal and Analysis. Except with respect to any Required Modification or Minor Resource Modification, AEPCO shall submit to the Member a document with respect to any proposed Resource Modification (Proposal and Analysis) containing: (i) the reasons therefor; (ii) the expected benefits and the estimated cost of implementing the proposal, demonstrating a positive benefits-to-costs relationship; (iii) the effect of implementing the proposal on the Member's AC and ACP, energy and cost; and (iv) an analysis of whether the period of AEPCO Indebtedness or the term of this Agreement will be extended to fund such proposed Resource Modification. The Proposal and Analysis shall be submitted to the Member and the time periods referred to in Section 3.4.4 shall have expired prior to the submittal of the proposed Resource Modification which is the subject of the Proposal and Analysis to the AEPCO Board of Directors.

3.4.4 Proposal and Analysis Review.

(a) Member shall notify AEPCO within thirty (30) business days of its receipt of any Proposal and Analysis whether Member consents to the proposed Resource Modification or that Member (i) disagrees with the Proposal and Analysis with the reasons for such disagreement; or

(ii) requires additional analysis to more fully understand such Proposal and Analysis.

(b) Upon receipt from Member of a notice of disagreement with any Proposal and Analysis or a request for further analysis, AEPCO shall prepare and submit to Member, within thirty (30) business days thereafter, a response to such disagreement or such request for additional analysis. AEPCO's response shall reflect the costs and benefits of the proposed Resource Modification to all Class A Members and demonstrate an aggregate positive benefit-to-cost ratio to the Class A Members.

(c) If Member believes that the correct benefit-to-cost ratio of such proposed Resource Modification is not positive, then Member shall provide to AEPCO within thirty (30) business days of its receipt of AEPCO's response under Section 3.4.4(b) above a writing: (i) setting forth its analysis of the benefit-to-cost ratio of the proposed Resource Modification and (ii) proposing any compromise which will, in its judgment, bring the proposed costs and benefits into balance for the Class A Members collectively. Member and AEPCO shall then enter into good faith negotiations to resolve their differences respecting such proposed Resource Modification.

(d) All activities contemplated by this Section 3.4.4 shall be concluded no later than one hundred twenty (120) days after the receipt by Member of any Proposal and Analysis which is the subject of dispute between the Parties. In the event that: (i) negotiations under Section 3.4.4(c) do not resolve the disagreement between the Parties with respect to a proposed Resource Modification; and (ii) the AEPCO Board of Directors approves any such Resource Modification pursuant to Section 3.4.5 hereof, then: (a) the AC of Member; (b) the term of this Agreement; or (c) the rates and Fixed Charge billed to Member may not be modified to provide for the collection of the costs, obligations or expenses for such Resource Modification, and Section 3.4.7 shall apply to Member. The ACP of Member may, however, be modified by AEPCO to maintain the AC of the Member in the Resource at the same level as its AC prior to the Resource Modification.

3.4.5 <u>Project Approval</u>. Any addition of, or modification to, an exhibit to Rate Schedule A as a result of: (a) a Resource Modification which is (i) a Generating Resource; or (ii) an extension of a then-existing Power Purchase Resource, with a new or extended term of greater than five (5) years; or (b) a modification which is not a Required Modification must, in either case, be approved by a majority vote of the AEPCO Board of Directors, including an affirmative vote of at least sixty-six and two-thirds percent (66 2/3%) of the directors representing the Class A Members prior to the AEPCO Board of Directors' authorization of the principal documents necessary to obligate AEPCO to a transaction resulting in such addition or modification to an exhibit to Rate Schedule A. Any such approval obtained pursuant to this Section 3.4.5 shall constitute a "Project Approval."

3.4.6 Member Approval. Following a Project Approval, the addition or modification specified in Section 3.4.5 hereof shall be submitted to Member for its written approval pursuant to this 3.4.6, unless the Member has previously given its requisite consent pursuant to Section 3.4.4. Such written approval of Member shall also constitute authority to make the necessary additions of, or modifications to, Rate Schedule A and Schedule B affecting Member's participation in the Resource Modification. Rate Schedule A and Schedule B shall accordingly be amended, as necessary, to reflect the addition of each Resource Modification. In the event Member consents in writing pursuant to Section 3.4.4 hereof or gives written approval within ten (10) business days after the submittal contemplated in this Section 3.4.6, the Member shall make all payments required pursuant to Section 3.4.1 with respect to such addition or modification to Rate Schedule A and Schedule B, including without limitation, an extension of the term of this Agreement.

3.4.7 Member Disapproval. In the event that Member elects not to approve any addition or modification specified in Section 3.4.5 in accordance with Section 3.4.4 or Section 3.4.6 hereof, then Member shall notify AEPCO in writing of such election.

3.5 Modification of AC for Reserves and Losses. In the event of: (i) a change in the reserve requirements which AEPCO is legally required to maintain, or (ii) an engineering study which is commissioned by TRANSCO demonstrates that the transmission loss percentage on the TTS needs to be changed in order to accurately reflect the actual losses on the TTS, AEPCO shall modify the AC of Member to reflect the AC available to Member after such change in reserve requirements or transmission losses. Such modified AC shall be effective as of the first billing period beginning no less than forty-five (45) days after Member has received notice of the modified AC.

4. RESOURCE POOL:

The Member shall include the electric capacity and energy to which it is entitled under this Agreement in the Resource Pool.

5. RATES AND CHARGES:

5.1 Billing and Payment. Electric capacity and energy furnished to Member pursuant to this Agreement shall be billed on a calendar month basis. AEPCO shall prepare monthly bills for electric capacity and energy service and send such bills by electronic transmission, with a copy placed in the U.S. Mail, return receipt requested, to the Member no later than the tenth (10th) day of the following calendar month. Member shall pay AEPCO the total amount of such bill by the later of (a) the twentieth (20th) day of the month that the bill is sent or (b) ten (10) days after receiving the bill by the earlier of (i) electronic transmission or (ii) U.S. Mail.

Member shall make payment by electronic wire transfer to a bank selected by AEPCO, or by any other method which provides Collected Funds to AEPCO on or before the payment due date. Amounts not paid by the due date shall be payable with interest accrued at the Contract Rate of Interest. Member shall make all payments to AEPCO that are required pursuant to this Agreement at the rates, Fixed Charge and other adjustments, and on the terms and conditions set forth herein and in Rate Schedule A, as amended from time to time, in accordance with Section 5.6 hereof. All such rates, Fixed Charge, and other such adjustments proposed or implemented by AEPCO shall be in accordance with the requirements of this Section 5, Section 8, Rate Schedule A and its obligations to the Financial Entities.

5.2 Fixed Charge. AEPCO shall charge, and the Member shall pay all fixed costs and expenses based on its ACP through the payment by the Member of an annual Fixed Charge as determined and set forth in, and due and payable, pursuant to Rate Schedule A.

5.3 O&M Charge. AEPCO shall charge, and the Member shall pay all operations and maintenance costs and expenses based on its Member Billing Demand through payment by the Member of a monthly O&M charge as determined, and set forth in, and due and payable, pursuant to Rate Schedule A, and Schedule B if applicable.

5.4 Energy Charge. Subject to Schedule B hereof, AEPCO shall charge, and the Member shall pay, the cost of energy actually delivered to the Member in accordance with Section 6.1 hereof through payment by the Member of a monthly energy charge as determined, and set forth in, and due and payable, pursuant to Rate Schedule A.

5.5 Schedule B Charge. AEPCO shall charge, and the Member shall pay, the charges calculated under Schedule B as applicable.

5.6 Rate and Fixed Charge Design and Revision. At such intervals as AEPCO shall deem appropriate, but in any event not less frequently than once in each calendar year, AEPCO shall review the rates and Fixed Charge for electric energy and capacity provided hereunder, under the MEC Partial Requirements Capacity and Energy Agreement, and under the Existing Wholesale Power Contracts with AEPCO's All Requirements Members. If such rates or Fixed Charges are to be revised, AEPCO shall cause a notice in writing to be provided to the Member, other Class A Members of AEPCO, and the Administrator, which notice shall set forth the proposed revisions of the rates or Fixed Charges with the effective date thereof, and the basis upon which the rates or Fixed Charges is proposed to be adjusted and set. The Member agrees that the rates and Fixed Charge from time to time set by AEPCO in Rate Schedule A shall be substituted for the rates herein provided and agrees to pay for electric energy and capacity provided by AEPCO hereunder after the effective date of any such revised rates and Fixed Charge pursuant to such revised rates and charges; provided that no such revised rates or Fixed Charge shall be effective if they have been disapproved in writing by the Administrator. AEPCO shall design and set future rates and the Fixed Charge based on Rate Schedule A to produce revenues that shall be sufficient, but only sufficient, with the revenues of AEPCO from all other sources to satisfy all of AEPCO's Revenue Requirement which is developed to provide revenues sufficient to meet all of AEPCO's obligations, including, but not limited to:(i) all of AEPCO's costs, obligations, and expenses; (ii) all payments on account of Indebtedness of AEPCO, including Indebtedness to RUS and others; (iii) the establishment and maintenance of reasonable financial reserves; and (iv) all requirements, including financial covenants and tests contained in the AEPCO Mortgage, AEPCO Loan Contract or in any other indenture, mortgage, security agreement or contract relating to any Indebtedness, the Secured Obligations or any other financial obligations of AEPCO as any of the foregoing may exist from time to time.

5.7 Resource Pool Settlement. Credits and charges from settlements related to the pooled operation of AEPCO Resources, and any other income belonging to AEPCO derived from the sale or use of such AEPCO Resources, shall be reflected in the rates and Fixed Charge charged to the Member in accordance with Rate Schedule A.

5.8 Accounting for Costs. AEPCO shall account to the Member, in accordance with Accounting Requirements, for its direct and indirect costs for AEPCO Resources and for each service that AEPCO provides to the Member.

5.9 Reasonable Rate. The Parties agree that the rates, Fixed Charge, rate methodology, and terms and conditions of service established hereunder are just and reasonable under the current circumstances and reflect their determination that any revisions, adjustments or changes to such rates or Fixed Charge established in accordance with this Agreement shall, in the future, be deemed just and reasonable and not unlawfully discriminatory under applicable Law. The rates and Fixed Charge take into account specific benefits achieved by the Parties through this Agreement and not otherwise available to the Parties, and reflect the sharing of those benefits without undue discrimination against any current or future customer or Member of AEPCO.

5.10 Covenant of the Member. The Member covenants and agrees to design, set and maintain its rates and charges at a level sufficient to collect payments for the service of its electric system, and to conduct its business in a manner which shall produce revenues and receipts at least sufficient to enable the Member to pay to AEPCO, when due, all amounts payable by the Member under this Agreement.

5.11 Cost Responsibility. The rates and charges and the Fixed Charge applicable to the Member pursuant to Exhibit A-1 to Rate Schedule A to meet the Revenue Requirement from Partial Requirements Member shall take into account all direct and indirect costs and revenues, including administration and general expenses, margins, revenues from the sale of electric energy, capacity and other services and investment gain and loss, allocated by AEPCO among the Existing Resources. Subject to Section 3.2.2, such rates and charges shall not take into account costs and revenues allocated by AEPCO to any Future Resource.

5.12 Recovery of Revenue Shortfall. AEPCO shall at all times design, set, maintain and collect payments on the basis of rates, a Fixed Charge and other adjustments to fully recover all costs, obligations and expenses, including, but not limited to, the occurrence of any Revenue Shortfall.

6. POINTS OF DELIVERY AND GENERAL TERMS AND CONDITIONS OF SERVICE:

6.1 Points of Delivery. Subject to Section 6.2, AEPCO shall furnish the electric capacity and energy purchased by the Member under this Agreement to the Member or the Member's transmission provider or agent for delivery to the Member at: (i) the low side of the step-up transformer at each Generating Resource of AEPCO with respect to electric energy and capacity that is produced by a Generating Resource of AEPCO that is interconnected with the TTS; and (ii) for a Power Purchase Resource of AEPCO, the interconnection point with the TTS where AEPCO takes title to such electric energy and capacity; or (iii) the interface with the TTS at which capacity is provided and electric energy is delivered to AEPCO from an AEPCO Resource that is not interconnected with the TTS. Title and risk of loss of such electric energy and capacity shall pass from AEPCO to the Member or Member's transmission provider or agent at such points of delivery. As among the Parties hereto, AEPCO shall be deemed to be in exclusive control and responsible for transmission losses and any injury and damage caused by the electric energy and capacity prior to the point of delivery, and the Member shall be deemed to be in exclusive control and responsible for transmission losses and any damage or injury caused by the electric energy and capacity at and from the point of delivery.

6.2 AEPCO and Member Covenants and Member Representations.

6.2.1 AEPCO and the Member shall use their respective best efforts to cause a constant and uninterrupted supply of electric energy and capacity to be delivered and received.

6.2.2 AEPCO covenants and agrees that it will operate, maintain and manage its Resources in accordance with Prudent Utility Practice.

6.2.3 Member covenants and agrees that it will operate, maintain and manage its electric system in accordance with Prudent Utility Practice.

6.2.4 The Member's ACP as set forth in Exhibit A-5 to Rate Schedule A is accepted by the Parties. The Member's ACP was based on certain load forecasts established in the 1996 Power Requirements Study. The Parties agree that such Power Requirements Study is an acceptable basis upon which to establish Member's ACP and to apply such ACP for cost responsibility under this Agreement.

6.2.5 The Parties agree that the rates, Fixed Charge, methodology and principles of cost allocation set forth in this Agreement are just and reasonable.

6.3 Metering for Billing Purposes.

6.3.1 For the purposes of applying billing units to the rates determined pursuant to this Agreement as set forth in Rate Schedule A, Member shall arrange with Member's transmission provider(s) or agent pursuant to Section 6.1 to timely communicate to AEPCO, Member's monthly peak demand and energy consumption from revenue quality metering installed at the Member's Delivery Points. AEPCO shall provide electric energy and capacity to such transmission provider(s) to satisfy the demand and energy losses incurred in transmission of Member's electric energy and capacity hereunder, as such losses are incurred between Member's points of delivery as set forth in Section 6.1 and such locations where Member takes delivery from such transmission provider(s).

6.3.2 Member shall require its transmission provider(s) or agent, pursuant to Section 6.1, to test and calibrate such metering by comparison with accurate standards at intervals of twelve (12) months. Upon the request of AEPCO, Member shall further require such transmission provider(s) or agent to make special meter tests at any time. The costs of all such special tests at AEPCO's request shall be borne by AEPCO; provided, however, that if any special meter test made at AEPCO's request discloses that the meters are recording inaccurately, the Member shall reimburse AEPCO for the cost of such test. Meters registering not more than one percent (1%) above or below nominal shall be deemed to be accurate. The readings from any meter which shall have been disclosed by any test to be inaccurate shall be corrected in accordance with the percentage of inaccuracy found by such test for a period equal to the lesser of: (i) the period of the inaccuracy, if determinable by AEPCO in conjunction with the Member and the transmission provider(s), or (ii) three (3) months previous to the month of such test. If any meter shall fail to register for any period, AEPCO shall render a bill therefor based upon AEPCO's estimate of Member's demand and energy consumption, as applicable.

6.3.3 Member shall notify AEPCO in advance of the time of any special meter test requested by AEPCO so that AEPCO may send a representative to be present at such meter test.

6.3.4 Any corrections in billing resulting from metering inaccuracies shall be made in the next monthly bill. In the event that the Parties are unable to resolve their differences, AEPCO shall render a bill or offer a credit, as the case may be, and the Member shall dispute that bill or credit only pursuant to Section 19 hereof.

7. <u>JOINT MARKETING AGREEMENTS</u>:

AEPCO and the Member acknowledge that CSP and Member may enter into a mutually acceptable joint marketing agreement (Joint Marketing Agreement) in order to facilitate effective competitive retail electric sales of electric energy and capacity in the Member's Distribution Service Area.

8. STRANDED COST RECOVERY:

8.1 Stranded Cost Recovery. In the event the ACC permits the recovery by AEPCO or Member of any Stranded Costs by means of a surcharge, fee, wires charge or any other recovery mechanism charged to or assessed against the Member's distribution customers, the Member shall collect and remit to AEPCO all such funds collected by Member that represent recovery of AEPCO's Stranded Costs, including any such Stranded Costs associated with this Agreement.

8.2 Recovery of Stranded Costs by AEPCO. AEPCO shall diligently and vigorously pursue legal and administrative action to recover all of the Stranded Costs of AEPCO described in Section 8.1. The Member shall join with AEPCO in recovering such Stranded Costs and the Parties will cooperate fully in seeking such recovery.

8.3 Recovery of Stranded Costs by Member. In the case of Stranded Costs not covered by the preceding Section 8.2, if the Member seeks recovery of its Stranded Costs for its electric system on its own, AEPCO shall assist the Member and shall supply the Member with any information in the possession or control of AEPCO at Member's reasonable request.

9. AUTHORIZED REPRESENTATIVES:

Each Party shall designate within thirty (30) business days after the execution of this Agreement, by written notice to the other Party, a representative who is authorized to act on its behalf in implementation of this Agreement and with respect to those matters contained herein which are the functions and responsibilities of the Authorized Representatives, provided that the Authorized Representatives shall have no authority to modify this Agreement. Either Party may, at any time, change the designation of its Authorized Representative by written notice to the other Party.

10. COMMITTEES:

As a means of securing effective cooperation, and of dealing on a prompt and orderly basis with various technical and operating issues that may arise in connection with AEPCO system development or operations under changing conditions, the Parties will establish a standing operating committee charged with certain responsibilities (Operating Committee). The Parties may establish other such committees or work groups as may be determined by the Authorized Representatives. Each Party shall bear its costs related to its participation in the Operating Committee and other such committees or work groups. The responsibility and authority of each committee shall be limited to technical and operating matters in connection with the implementation of this Agreement and shall not extend to other affairs of the Parties.

11. RIGHTS OF ACCESS, RECORDS AND ACCOUNTS:

11.1 Rights of Access. Duly authorized representatives of either Party hereto shall be permitted to enter the premises of the other Party hereto at all reasonable times in order to implement this Agreement.

11.2 Accounting Records. AEPCO shall keep accurate records and accounts in accordance with Accounting Requirements. Promptly after the close of each fiscal year (and not later than 120 days after the end of each fiscal year), AEPCO shall cause such records and accounts of all transactions of AEPCO with respect to such fiscal year to be subject to an annual audit conducted in accordance with Accounting Requirements by a firm of independent certified public accountants experienced in electric utility accounting and possessing a national reputation in accounting and auditing. AEPCO shall without delay provide a copy of each such annual audit, including all written comments and recommendations of such accountants to the Member and, so long as AEPCO is a borrower thereof, to RUS.

11.3 Access to Books and Records. The Member shall at all times have reasonable access during business hours to examine or audit any and all of the books, records and supporting worksheets and data of AEPCO, as may be appropriate, to determine the accuracy of any charges or payments required to be made by the Member to AEPCO. If such books, records and supporting worksheets and data of AEPCO contain information about another Member of AEPCO, AEPCO shall excise any identification of a specific Member or provide such information to the Member or its independent certified public accountant or other independent representative of the Member under a confidentiality agreement. If, after such examination or audit of AEPCO's records, there exists a dispute as to the accuracy of any charge and the Parties proceed to resolve such dispute under Section 19 hereunder, Section 22.5 hereof shall apply.

11.4 Materiality, Standards, Time Periods. Prior to any audit of AEPCO's records, AEPCO's internal auditor and the Members' auditor shall plan the examination's analytical procedure of the audit and shall agree on a materiality threshold for acceptable individual and accumulated misstatements (both over and under billings) of cumulative billing amounts. For purposes of this Section 11.4, "cumulative" shall mean the billing periods being audited. Any audit of AEPCO's records shall be made in accordance with Generally Accepted Auditing Standards and shall be limited to AEPCO's current and prior three (3) fiscal years.

12. REORGANIZATIONS, TRANSFERS AND SALES OF ASSETS BY THE MEMBER:

12.1 Dissolution or Liquidation. The Member shall not dissolve, liquidate or otherwise wind up its affairs without the separate approvals in writing of each of AEPCO and the Administrator while this Agreement remains in effect. In each such case, such approval shall not be unreasonably withheld.

12.2 Permitted Member Transactions. So long as this Agreement remains in effect, Member shall not, nor suffer any effort to, consolidate or merge with any other Person or reorganize or change the form of its business organization from an electric cooperative non-profit membership corporation or sell, transfer, lease or otherwise dispose of all or substantially all of its assets (each, a "Member Transaction") to any Person (or make any agreement therefor), whether in a single transaction or series of transactions, unless:

(a) Such Member Transaction is expressly approved in separate writings by AEPCO and the Administrator; provided that neither AEPCO nor the Administrator will withhold or condition its consent except in cases where to do otherwise would, in the determination of AEPCO or the Administrator, as applicable, result in rate increases for the other Class A Members of AEPCO; impair the ability of AEPCO to satisfy the Secured Obligations in accordance with their terms; substantially increase AEPCO's capacity and energy sales requirements; or adversely affect system performance in any material manner; or

(b) All of the following conditions are satisfied:

(i) The Transferee shall be an entity organized and existing under the laws of the United States of America or any State or the District of Columbia; and

(ii) No default, breach or event which, with the lapse of time or the giving of notice, or both, could be expected to result in a breach, of this Agreement shall have occurred and be continuing; and

(iii) The Transferee shall execute and deliver to AEPCO an instrument supplemental hereto in form reasonably satisfactory to AEPCO containing an assumption by the Transferee of the performance and observance of every covenant and condition of this Agreement required to be performed or observed by the Member, and accepting and assuming all obligations and liabilities under this Agreement; and

(iv) A firm of independent certified public accountants shall prepare for the two calendar years immediately preceding the Member Transaction a set of pro forma financial statements that assume the consummation of the Member Transaction through the applicable determination period and that are prepared in accordance with Generally Accepted Accounting Principles. Based on such pro forma financial statements, such accountants must certify that:

(A) the Transferee's Debt Service Coverage Ratio is at least a level of 1.25 and Times Interest Earned Ratio is at least a level of 1.25 for each of the two immediately preceding calendar years (assuming such Member Transaction had been consummated at the beginning of such two-year period);

(B) the Transferee's Equity equals at least 30% of its Total Assets after giving effect to such Member Transaction; and

(C) the ratio of the Transferee's Net Utility Plant to its Long-Term Debt is at least a level of 1.0 after giving effect to such Member Transaction.

The specification of conditions in Section 12.2(b) shall not be construed to establish standards under which the Member may effect a Member Transaction. The purpose of such conditions is to establish when approval by AEPCO or the Administrator need not be obtained.

12.3 Service Territory and Electric System. The Member shall not voluntarily convey, transfer, lease, or otherwise dispose of any part of its electric system or assigned service territory or voluntarily transfer or assign to another Person any customer of the Member (each, a "Conveyance") if such Conveyance, considered together with: (i) all prior Conveyances, and (ii) all prior additions (by construction, conveyance, transfer or lease to the Member) to its electric system, assigned service territory or customers, could reasonably be expected to have a material adverse affect on the Member's ability to perform its obligations under this Agreement.

13. ASSIGNMENTS:

13.1 General.

13.1.1 Except as otherwise set forth in this Section 13, this Agreement shall be binding upon and inure to the benefit of the permitted successors and permitted assigns of the Parties. This Agreement may not be assigned by either Party unless prior consent to such assignment is given in writing by (i) the other Party, which consent shall not be unreasonably withheld and (ii) the Administrator, in its sole discretion, if either Party is then a RUS borrower. Any assignment made without a consent required hereunder shall be void and of no force or effect as against the non-consenting Party or RUS, as the case may be.

13.1.2 No sale, assignment, transfer or other disposition permitted by this Agreement shall effect, release or discharge either Party from its rights or obligations under this Agreement, except as may be expressly provided by this Agreement.

13.2 Assignment for Security.

13.2.1 Notwithstanding any other provision of this Agreement, a Party, without the other Party's consent, (but if such assigning Party is a borrower of RUS, then only with the consent of the Administrator) may enter into an Assignment for Security for any obligation secured by any indenture, loan contract, mortgage, financial instrument or similar lien on its system assets. Such Assignment for Security shall be without limitation on the right of the secured party to further assign this Agreement, including, without limitation, the assignment by the Member or AEPCO to create a security interest for the benefit of RUS, or for the benefit of any third party with the consent of the Administrator, if such assigning Party is a borrower of RUS.

13.2.2 The Parties acknowledge that, as a permitted assignee through an Assignment for Security, the Administrator or other secured party, without the approval of the other Party to this Agreement, may: (i) cause this Agreement to be sold, assigned, transferred or otherwise disposed of to a third party pursuant to the terms governing an Assignment for Security; or (ii) sell, assign, transfer or otherwise dispose of this Agreement to a third party (if RUS or other secured party first acquires this Agreement); provided, however, that in either case the Party who made the Assignment for Security first is in default of its obligations to RUS or other secured party that is secured by such security interest.

13.3 Corporate Reorganization by AEPCO.

13.3.1 Subject to the prior written approval of the Administrator while AEPCO is a RUS borrower, AEPCO may assign any or all of its rights and delegate any or all of its duties under this Agreement in connection with any reorganization, merger or consolidation of AEPCO with another entity in which AEPCO is not the surviving entity.

13.3.2 Subject to the prior written approval of the Administrator while AEPCO is a RUS borrower, AEPCO may, in its sole discretion, at any time and from time to time, retire, sell, transfer, lease, terminate or otherwise dispose of any AEPCO Resource (even though such transaction may reduce or eliminate the electric energy and capacity available to the Member with respect to such Resource), subject to the provisions of Sections 2.1 and 2.2 of this Agreement.

13.4 Receiver or Trustee in Bankruptcy. The Parties intend that the rights and obligations of the Member under this Agreement shall not be affected by a receiver, a trustee in bankruptcy, a mortgagee or an indenture trustee assuming control of the assets or business of AEPCO, and that such receiver, trustee, mortgagee or indenture trustee may exercise all of the rights of, and shall meet all the obligations, including those to the Member, and make all of the determinations provided to be made in this Agreement by the AEPCO Board of Directors or AEPCO, as the case may be.

13.5 Express Rejection of Implied Limitations. The Parties intend that this Agreement shall be assignable by AEPCO in accordance with the provisions of this Section 13 without regard to any other provisions of this Agreement, the nature of the Person to whom this Agreement is assigned, or the issues raised in the case, *In the Matter Of Wabash Valley Power Assn., Inc.*, 72 F.3d 1305 (7th Cir. 1995); provided that the assignee in any assignment (other than an Assignment for Security) shall at the time of such assignment deliver to the Class A Members, including Member, a written assumption of AEPCO's obligations and liabilities pursuant to this Agreement. The Parties agree that this Agreement may be assigned by AEPCO to any Person (including any receiver or trustee in bankruptcy) pursuant to this Section 13 without regard to the fact that: (i) such Person is not a cooperative; (ii) the Board of Directors of such Person, if any, is not chosen by a vote in which the Member participates; or (iii) such Person is not operated on a not-for-profit basis. Further, no other provision of this Agreement shall restrict the assignment of this Agreement by AEPCO pursuant to this Section 13.

14. EVENTS OF DEFAULT AND REMEDIES:

14.1 Payment Default. If the Member fails to make full payment to AEPCO when required to be made under this Agreement, and such failure continues for a period of five (5) business days, AEPCO shall give written notice to the Member. If the Member does not, within ten (10) days from the date of the receipt of such notice, pay the full outstanding amount then due to AEPCO, together with interest thereon computed at the Contract Rate of Interest, such failure shall constitute a "Payment Default" on the part of the Member. AEPCO shall promptly provide written notice to the other Class A Members of the Payment Default. The amount of any such payment not paid in full when due shall thereafter accrue an interest charge at the Contract Rate of Interest.

14.1.1 Upon a Payment Default, AEPCO may, upon twenty-four (24) hours prior written notice, suspend service to the Member for the period of the continuing Payment Default. AEPCO's right to suspend service shall not be its sole and exclusive remedy, but shall be in addition to all other remedies available to AEPCO at law or in equity. No suspension of service under, or termination of, this Agreement or recovery of additional revenues from other Members of AEPCO shall relieve the Member of its obligations or outstanding liability for any amount owed by it to AEPCO hereunder, which are absolute and unconditional. AEPCO shall make reasonable efforts to mitigate the expense to Member by marketing at commercially reasonable prices the capacity and energy whose delivery to the Member under Section 6.1 hereof has been suspended; provided the Member shall have a continuing obligation to make all payments to AEPCO required to be made pursuant to this Agreement. AEPCO shall credit the obligations of the Member during any suspension of service with the monies actually received by AEPCO from sales of capacity and energy (less any damages attributable to the Payment Default and all costs and expenses of re-marketing such capacity and energy) that would have been available to serve the Member; provided that AEPCO, in absence of gross negligence or willful misconduct, shall not be responsible to Member for failure to otherwise mitigate the consequences of the Member's Payment Default.

14.1.2 AEPCO may terminate this Agreement if a Payment Default shall have occurred and is continuing.

14.1.3 AEPCO shall commence such suits, actions or proceedings, at law or in equity as may be necessary or appropriate to enforce the obligations of the Member under this Agreement.

14.2 AEPCO's Failure to Deliver. As provided for in Section 2.6 and except as provided in Section 22.2 hereof, if AEPCO fails to provide electric energy and capacity as required by Section 2.2 hereof, AEPCO shall promptly provide notice to Member upon learning of a failure to deliver electric energy and capacity services and use its best efforts to restore service to Member. If AEPCO is unwilling to restore or provide substitute service pursuant to Section 2.2 hereof, AEPCO shall reimburse the Member for the reasonable direct and verifiable costs incurred by Member to obtain and replace such electric energy and capacity that AEPCO was unwilling to restore or provide, but the Member shall not be entitled to terminate this Agreement or to withhold payments required to be made pursuant to this Agreement.

14.3 Performance Default. If either Party fails materially to comply with any of the terms, conditions and covenants of this Agreement (and such failure does not constitute a Payment Default by the Member or a failure to deliver as set forth in Section 14.2), the non-defaulting Party shall give the defaulting Party written notice of the default (Performance Default). The defaulting Party shall have a period of ten (10) business days after receipt of such notice to cure such Performance Default; provided, however, that in the event the nature of the default is such that it can be cured but cannot reasonably be cured during such ten (10) business day period, the defaulting Party shall not be deemed in default so long as the defaulting Party promptly commences to remedy the default and diligently prosecutes such remedy to completion. In the event that the defaulting Party does not cure such Performance Default as herein provided, the non-defaulting Party, subject to Section 14.4.3, shall have all of the rights and remedies provided at law and in equity, other than termination of this Agreement.

14.4 Remedies.

14.4.1 Notwithstanding any provision to the contrary set forth in the AEPCO restructuring, the Parties do not intend that their respective rights and obligations arising under this Agreement as a factual matter shall be deemed special, unique and extraordinary in nature.

14.4.2 Every right, obligation and remedy of a Party may be exercised concurrently, or separately, from time to time, and so often and in such manner as may be deemed expedient by the exercising Party, and the exercise of any such right, obligation and remedy shall not be deemed a waiver of the right to exercise at the same time or thereafter, any other right, obligation or remedy.

14.4.3 No remedy conferred upon or reserved by AEPCO or the Member under this Agreement is intended to be exclusive of any other remedy or remedies available hereunder or now or hereafter existing; provided that no Performance Default by AEPCO shall permit the Member to terminate this Agreement or relieve the Member of its obligation to make payments pursuant to this Agreement, which obligation shall be absolute and unconditional and no default other than a Payment Default shall relieve AEPCO of its obligation to deliver the Member's allocated capacity and associated energy in accordance with Sections 2.2 and 6 hereof.

14.4.4 No waiver by either Party hereto of any one or more defaults by the other Party hereto in the performance of any provision of this Agreement shall be construed as a waiver of any other default or defaults, whether of a like kind or different nature.

14.4.5 AEPCO and the Member agree for their benefit and that of RUS that: (a) if the Member fails to comply with any provision of this Agreement, AEPCO and the Administrator shall have the right to enforce the obligations of the Member under this Agreement and (b) if AEPCO shall fail to comply with any provision of this Agreement, the Member or the Administrator shall have the right to enforce the obligations of AEPCO under this Agreement. Such enforcement may be through the instituting of all necessary actions at law or suits in equity, including, without limitation, suits for specific performance. Such rights of the Administrator to enforce the provisions of this Agreement are in addition to and shall not limit the rights which RUS shall otherwise have as third party beneficiary of this Agreement or pursuant to the assignment and pledge of this Agreement and the payments required to be made hereunder as provided in the AEPCO Mortgage.

14.4.6 The rights of RUS under this Agreement shall terminate when AEPCO is no longer a borrower of RUS.

15. EFFECTIVENESS AND TERM:

This Agreement is dated as of the date of execution and shall become effective upon the Agreement Date and, unless terminated by AEPCO in accordance with Section 14.1.2, shall remain in effect until December 31, 2035, unless extended further pursuant to Sections 3.3 and 3.4 hereof by the written agreement, consent or notice of Member given pursuant to Section 3 hereof. After December 31, 2035 (or such date to which the term hereof may have been extended), the Parties will enter into negotiations to determine their future relationship, if any, recognizing the past revenue payment which Member has made in support of the AEPCO Resources.

16. AMENDMENTS, CONFLICTS, AND COUNTERPARTS:

16.1 Amendments.

(a) Except as provided in Sections 16.1(b) and (c) below, no amendment to this Agreement shall be effective unless: (i) such amendment is in writing; (ii) executed by both Parties; and (iii) reviewed and approved in writing by the Administrator.

(b) No amendment to the rate-setting methodology of Rate Schedule A governing Existing Resources shall be effective unless: (i) approved by both Parties and by all other Class A Members; and (ii) reviewed and approved in writing by the Administrator.

(c) No amendment to Exhibits A-1, A-3 (as required by Accounting Requirements) or A-5 pursuant to Sections 3.3, 3.4 or 3.5 above to Rate Schedule A or Schedule B or any other Exhibit or schedule hereto shall be effective unless approved by the AEPCO Board of Directors, and reviewed and approved in writing by the Administrator.

16.2 Entire Agreement. This Agreement constitutes the entire agreement between the Parties relating to the subject matter of this Agreement and supersedes all previous agreements, whether oral or written, including without limitation, the Existing Wholesale Power Contract between AEPCO and Member. A copy of the Member Agreement is attached hereto as Attachment A for the sole limited purpose of providing information involving Member related to the restructuring of AEPCO and is not incorporated into this Agreement by reference thereto. Rate Schedule A, Schedule B and Appendix A are incorporated herein by reference and all amendments thereto approved under Section 16.1 hereof shall be attached hereto and thereby incorporated herein.

16.3 Conflicts.

16.3.1 In the event of any conflict between the provisions of this Agreement and any other agreement between the Parties, the provisions of this Agreement shall govern.

16.3.2 In the event of any conflict between the provisions of Sections 1 through 22, inclusive, of this Agreement and the provisions of Rate Schedule A or of any amendments to Rate Schedule A or any future exhibits, appendices or schedules attached thereto, the provisions of Sections 1 through 22, inclusive, of this Agreement shall govern.

16.4 Counterparts and Facsimile Delivery. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. Any Party may deliver an executed copy of this Agreement and an executed copy of any other document contemplated hereby by facsimile transmission to the other Party, so long as subsequently confirmed in the manner set forth in Section 21, and such delivery shall have the same force and effect as any other delivery of a manually signed copy of this Agreement or such other document. Each Party and RUS shall receive and retain one counterpart with original signatures of the Parties and shall provide a copy thereof to the other Party or RUS upon request.

17. SEVERABILITY:

If any part or any provision of this Agreement shall be held invalid or unenforceable by any Governmental Authority having jurisdiction under applicable Law, said part or provision shall be ineffective only to the extent of such invalidity without in any way affecting the remaining parts of said part or provision or the remaining provisions of this Agreement. In the event that such invalidity alters the relationship of the Parties to the significant disadvantage of a Party, the Parties shall attempt to negotiate a modification of the terms of the Agreement in order to reestablish the original balance of benefits, and if such agreement is not reached, the disadvantaged Party may seek reformation of the Agreement through the dispute resolution process provided in Section 19 herein.

18. GOVERNING LAW:

Except to the extent governed by applicable federal Law, this Agreement shall be governed by, and construed in accordance with, the Laws of the State of Arizona, without giving effect to its conflicts of law principles.

19. DISPUTE RESOLUTION:

19.1 Dispute Resolution Committee. Upon a dispute arising between the Parties, AEPCO and the Member shall each designate one representative to serve on a Dispute Resolution Committee, which shall be assigned disputes or matters for resolution by the Authorized Representatives of AEPCO and the Member.

19.2 Mediation. Except as otherwise provided herein, the Parties shall first in good faith seek to resolve any dispute arising hereunder through negotiation. If such dispute cannot be settled through negotiations, or if the Dispute Resolution Committee is unable to resolve a dispute on a matter submitted to it within the time frame established by the Authorized Representatives, the Parties agree to try in good faith to settle the dispute by mediation under the Commercial Mediation Rules of the American Arbitration Association, before resorting to some other dispute resolution procedure; provided that a Party may not invoke mediation unless it has provided the other with written notice of the dispute and has attempted in good faith to resolve such dispute through negotiation. Notwithstanding the foregoing, any Party may seek immediate equitable relief, without attempting to settle a dispute through mediation.

20. MEMBER'S WITHDRAWAL FROM AEPCO:

20.1 Member Withdrawal. If the Member elects to withdraw from membership in AEPCO, the terms of this Agreement shall remain in full force and effect except as provided in the Withdrawal Agreement executed by AEPCO and the Member.

20.2 References. For the purposes of this Agreement, each reference to the "Member" shall mean (i) the withdrawn Member from and after the effective date of the Member's withdrawal from AEPCO in accordance with the Withdrawal Agreement, or (ii) any permitted assignee (other than an assignee pursuant to an Assignment for Security) from and after the effective date of an assignment of this Agreement by the Member as provided in the Withdrawal Agreement. Each reference to a "Member" or to the "Members" of AEPCO shall include any Class A Member or Members (i) which withdraw or have withdrawn from AEPCO as provided above; (ii) whose membership in AEPCO has been suspended or terminated; or (iii) any permitted assignee (other than an assignee pursuant to an Assignment for Security) of such Class A Member or Members, except that any reference to an approval of the

Class A Members shall not include any withdrawn Member or Members or such permitted assignees.

21. NOTICES:

All communications, notices, requests, demands, authorizations, consents, waivers or other modifications provided, permitted or required by this Agreement shall be communicated in writing or by a telecommunications device capable of creating a written record, and any such notice shall become effective: (a) upon personal delivery thereof, including, without limitation, by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by such a telecommunications device, upon transmission thereof, provided such transmission is promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to either Party hereto at its address set forth below or, in the case of either such Party hereto, at such other address as such Party may from time to time designate by written notice to the other Party hereto.

If to AEPCO:	Arizona Electric Power Cooperative, Inc. P.O. Box 670 1000 South Highway 80 Benson, Arizona 85602 Attention: Executive Vice President and Chief Executive Officer Fax: (520) 586-5576 or 5402
If to Member:	Sulphur Springs Valley Electric Cooperative, Inc. P.O. Box 820 Willcox, Arizona 85644 Attention: Chief Executive Officer Fax: (520) 384-2221

22. MISCELLANEOUS:

22.1 Indemnification, Mutual Indemnification, Risk of Loss and Insurance Obligations.

(a) Indemnification. The Member shall indemnify and hold AEPCO harmless from and against any and all losses, costs, liabilities, damages and expenses (including without limitation attorneys' fees and expenses through appeal) of any kind incurred or suffered by AEPCO, or any third party, pursuant to, as a result of, or in connection with any resale by the Member of capacity, energy or both except for losses, costs, liabilities, damages and expenses (including without limitation attorneys' fees and expenses through appeal) caused by AEPCO, including increased costs referred to in Section 14.2 hereof, or any third party, as a result of an act or omission that (a) is not Prudent Utility Practice or (b) is a breach of this Agreement.

(b) Mutual Indemnity. Except as otherwise provided in Section 22.1(a) above, Member and AEPCO shall each indemnify and save each other Party and the directors, agents, officers, and employees of each such other Party, harmless from and against any liability, loss, damage, claims, costs, and expenses (including reasonable attorneys' fees and court costs through appeal) incurred or claimed on account of injury to persons (including death) or damage or destruction of property, occasioned by the act or omission of the indemnifying party or its directors, officers, employees, agents or contractors in the performance of this Agreement, except to the extent that such liability, loss, damage, claim, costs, or expense results from the gross negligence or willful misconduct of the indemnified party; provided however, that:

(i) Each Party shall be solely responsible to its own employees and employees of third parties who are contracted to perform work for it, for all claims or benefits due for injuries occurring in the course of their employment or arising out of any workers' compensation law (except for claims for which the action or nonactions of the other Party was a proximate cause of such claims for benefits which are recoverable by the Party's employees from the other Party), and each Party shall indemnify and save the other Party harmless from and against any liability, loss, damage, claims, costs, and expenses (including reasonable attorneys' fees and court costs through appeal) relating to its own employees or employees of third parties who are contracted to perform work for it for such claim or benefit, except for such exception.

(ii) To the fullest extent permitted by Law, neither Party shall be liable to the other for any indirect, consequential, multiple or punitive damages.

(c) Risk of Loss. Except as otherwise provided in this Section 22.1 and except for loss, injury, damages, or destruction that result from a breach or default of a Party's duty or obligation as set forth herein, Member and AEPCO shall each bear their own respective risk of loss for any loss, injury, damage, or destruction to their respective property, facilities, equipment and for the replacement or repair of such property.

(d) Insurance Obligations. The Parties agree to obtain and maintain, at a minimum, levels of insurance coverage in accordance with Prudent Utility Practice. The provisions of this Section 22.1 shall not be construed so as to relieve any insurer of its obligation to pay any insurance proceeds in accordance with the terms and conditions of any insurance policy of any Party.

22.2 Force Majeure. No Party shall be considered to be in default in the performance of any of its obligations under this Agreement when a failure of performance shall be due to a Force Majeure. The Party claiming excused failure of performance shall promptly contact the other Party and, upon the written request of such other Party, shall promptly provide evidence that a Force Majeure has caused failure of performance. Any Party rendered unable to fulfill any obligation by reason of a Force Majeure shall exercise due diligence to remove such inability with all reasonable dispatch. Nothing contained herein shall be construed so as to require a Party to settle any strike or labor dispute in which it may be involved.

22.3 Other Corporate Documents. Whenever this Agreement authorizes AEPCO to otherwise amend a schedule hereto, to develop and implement policies or to make other decisions or do other acts in its sole discretion, AEPCO shall do so substantially in accordance with the applicable provisions of its duly adopted articles of incorporation, bylaws and corporate policies, and AEPCO shall not do so contrary to this Agreement. Any failure on the part of AEPCO to comply with this Section 22.3 shall not relieve the Member of any obligation under this Agreement which existed prior to such failure to act or act of AEPCO, but the Member shall not otherwise be prevented or limited in asserting any other rights it may have against AEPCO in respect of such failure.

22.4 Information Requirements. AEPCO and the Member shall each furnish to the other promptly upon request any and all information about itself, its financial condition, business and properties which may be necessary or desirable to facilitate any financing undertaken by the requesting Party or for any continuing disclosure obligation incurred by the requesting Party in connection with any such financing. The supplying Party shall be responsible only to the requesting Party for the accuracy and completeness of the information furnished and shall have no responsibility or liability for the manner in which such information is used or its appropriateness for such use. The supplying Party shall have no liability to any third party to which the requesting Party may furnish this information or any excerpt therefrom or summary thereof and shall be entitled to receive appropriate assurances and indemnities from the requesting Party to that effect as a condition to providing such information, provided that no such assurance or indemnity shall relieve the supplying Party of liability to the requesting Party for the accuracy and completeness of the information supplied.

22.5 Confidentiality.

(a) The Parties acknowledge that during the course of this Agreement, the Parties will have access to Confidential Information of AEPCO, the Member, and others. The Parties agree that the Parties or any persons employed by the Parties shall not, during the term of this Agreement or at any time thereafter, use or disclose any such Confidential Information to third parties and that the Parties shall take appropriate measures to protect the Confidential Information and prevent its disclosure. The Parties further agree that while AEPCO shall have access to Member's load and sales forecasts, AEPCO shall not, during the term of this Agreement or at any time thereafter, share or disclose such Member's Confidential Information in the specific with other Members of AEPCO, but may do so only in the aggregate form, i.e., to include such information in an aggregate total of load or sales forecasts for all of the Class A Members. The Parties further agree not to disclose to any other Person, or otherwise display for any purposes any books, records, worksheet, data, invoice, document, drawing, letter, report, tape or any other media, or any copy or reproduction thereof, belonging to, generated by, or pertaining to the other Party without written authorization from a duly authorized representative of the other Party. Before a Party communicates any Confidential Information to that Party's professional consultants, including, but not limited to, attorneys, accountants, investment bankers, brokers, bankers, technical and rate consultants, and engineers, such Party shall expressly advise such professional consultants in writing that the Confidential Information to be communicated must be kept confidential and shall not be made available to, or communicated to third parties. Such Party shall be responsible for any breach of this Section 22.5(a) by any such professional consultant. Before a Party communicates the Confidential Information to such professional consultants, the Party shall require that such professional consultants furnish a certificate to the Party acknowledging an agreement to comply with the provisions of this Section 22.5(a). Before such professional consultants make available or communicate such Confidential Information to anyone in the employ of such professional consultant, or to the firm to which such professional consultant belongs, such professional consultant shall obtain, and furnish to the Party, a certificate from such employee or firm acknowledging an agreement to comply with the provisions of this Section 22.5(a). This Section 22.5(a) shall not apply to Confidential Information requested of a Party by a Governmental Authority having jurisdiction.

(b) For purposes of this Agreement, "Confidential Information" means any and all information of either Party that is not generally known by others with whom the Party does or plans to compete or do business. Confidential Information includes without limitation such information, whether written or oral, related to: (i) a Party's development, research, testing, system, operations, and production activities; (ii) all products invented, researched, developed, planned, tested, manufactured, sold, licensed, leased, or otherwise distributed or put into use by the Party, together with all services provided or planned by the Party during the term of this Agreement; (iii) the Party's costs, sources of supply, strategic plans, resource plans, and capacity; (iv) the Party's pricing, cost-of-service, methods of allocation; (v) the identity and special needs of the customers, Members and other organizations with whom the Party has business relationships and the nature of those relationships; (vi) the Party's sales contracts and their terms and conditions; and (vii) the Party's marketing studies, surveys, plans and projections. Confidential Information also includes information that the Party receives or has received as confidential belonging to those who do business with it and, except to the extent disclosed by the Party on a non-confidential basis, any intellectual property.

"Confidential Information" does not include information that is generally available to the public or becomes generally available to the public or information given pursuant to an order of a Governmental Authority of competent jurisdiction, provided that the Party shall promptly advise the other Party of any subpoenas or other process served on the Party requesting information that would otherwise be confidential to enable the other Party to take such action as it determines to be appropriate to protect its rights and interests.

(c) The Parties further agree to enter into written agreements regarding the non-disclosure and the non-use of Confidential Information when requested to do so by other organizations, which provide proprietary data requested or obtained by the Party in connection with this Agreement.

22.6 Third Party Beneficiaries. AEPCO and the Member agree that RUS, while either the Member or AEPCO is a borrower of RUS, is a third-party beneficiary of this Agreement. AEPCO and the Member further agree that no other Member of AEPCO nor any other third party, except RUS, is a third-party beneficiary of this Agreement.

22.7 Obligations of RUS. The Parties agree that RUS shall not, merely due to an Assignment for Security, be deemed to assume or be bound to perform the duties of either Party to this Agreement, except to the extent the Administrator shall agree in writing to accept and be bound by such obligations.

22.8 Validity of Agreement. AEPCO and Member acknowledge and agree that the terms and conditions of the Agreement are valid, binding and enforceable as to AEPCO and Member according to its terms.

22.9 Headings. The descriptive headings of the various sections of this Agreement and the Exhibit and Schedules attached hereto have been inserted for convenience of reference only and shall not be construed as to define, expand, or restrict the rights and obligations of the Parties.

22.10 Waiver of Trial by Jury. Any suit, action or proceeding, whether claim, counterclaim or cross-claim, brought or instituted by either Party hereto on or with respect to this Agreement or any event, transaction or occurrence arising out of or in any way connected with this Agreement shall be tried only by a court and not by a jury. **EACH PARTY HEREBY EXPRESSLY WAIVES ANY RIGHT TO A TRIAL BY JURY IN ANY SUCH SUIT, ACTION OR PROCEEDING. THIS WAIVER OF RIGHT TO TRIAL BY JURY IS GIVEN KNOWINGLY AND VOLUNTARILY BY EACH PARTY, AND IS INTENDED TO ENCOMPASS INDIVIDUALLY EACH INSTANCE AND EACH ISSUE AS TO WHICH THE RIGHT TO A TRIAL BY JURY WOULD OTHERWISE ACCRUE. A PARTY MAY FILE A COPY OF THIS PARAGRAPH IN ANY PROCEEDING AS CONCLUSIVE EVIDENCE OF A PARTY'S WAIVER OF TRIAL BY JURY.**

22.11 Attorneys Fees and Legal Expenses. If any arbitration proceeding or action shall be brought to recover any amount under this Agreement, or for, or on account of any breach of, or to enforce or interpret any of the terms, covenants, or conditions of this Agreement, the prevailing Party shall be entitled to recover from the other Party, as part of the prevailing Party's costs, reasonable attorneys' fees through any appeal, the amount of which shall be fixed by the arbitrators or by the court, and shall be made a part of any award or judgment rendered.

22.12 Venue. The proper venue for any proceeding at law or in equity or under the provisions for arbitration shall be Maricopa County, Arizona, and the Parties waive any right to object to the venue.

22.13 RUS Approval No Waiver. The Parties hereby acknowledge and agree that the approval by the Administrator of this Agreement shall not in any way constitute or be deemed to be a waiver by RUS of any of its rights, or any of AEPCO's obligations under the AEPCO Loan Contract, any AEPCO Note, loan or security agreement between RUS and AEPCO or under applicable RUS regulations. The Parties further agree that, in the event of a conflict between this Agreement and such AEPCO Loan Contract, AEPCO Note, loan or security instrument or applicable RUS regulations in effect on the Agreement Date, the terms of such AEPCO Loan Contract, AEPCO Note, loan or security instrument or the applicable regulation in effect on the Agreement Date shall prevail.

22.14 Status as Member No Defense. The Member shall not assert as a defense, offset or condition to any of its obligations hereunder any rights, claims or defenses that the Member may have against AEPCO due to or arising out of the Member's status as a Class A Member of AEPCO (including any rights, claims or defenses contained in or arising out of the AEPCO Bylaws or Articles of Incorporation) or any other relationship between the Member and AEPCO other than the relationship established under this Agreement.

IN WITNESS WHEREOF, AEPCO and the Member have caused this Agreement to be executed, attested, and delivered by their respective duly authorized officers as of the 29th day of December, 2005.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
By: Donald W. Kimball
Name: Donald W. Kimball
Title: Executive Vice President and Chief Executive Officer

ATTEST:
By: Mark W. Schwirtz
Name: Mark W. Schwirtz
Title: Senior Vice President and Chief Operating Officer

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
By: Gene Manring
Name: Gene Manring
Title: President

ATTEST:
By: Curtis Nolan
Name: Curtis Nolan
Title: Secretary

RATE SCHEDULE A

TO PARTIAL REQUIREMENTS

CAPACITY AND ENERGY AGREEMENT

BETWEEN

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

AND

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.

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LIST OF EXHIBITS

RATE SCHEDULE A

1. INTRODUCTION:

This Rate Schedule A specifies the rates and Fixed Charge and the methodology for developing and administering those rates and the Fixed Charge for capacity and energy sales made by AEPCO to a Partial Requirements Member pursuant to the Partial Requirements Capacity and Energy Agreement (the "Agreement") to which this Rate Schedule A is attached.

Exhibit A-1 to this Rate Schedule A sets forth the rates and Fixed Charge which are currently in effect in accordance with the Agreement. Exhibit A-2 specifies the methodology for calculating the rates and Fixed Charge, utilizing the treatment of expenses and certain revenues or credits depicted in Exhibit A-3 and the calculation of ACP and AC in Exhibit A-5. Exhibit A-4 sets forth a sample of the bill to be presented to Member by AEPCO for services provided pursuant to the Agreement.

This Rate Schedule A applies to AEPCO's Resources in existence as of the Agreement Date and those in which the Partial Requirements Member obtains an ACP in accordance with the Agreement.

2. CONDITIONS OF SERVICE:

2.1 Applicability.

The rates, Fixed Charge and methodology for setting such rates, charges and adjustments is set forth in this Rate Schedule A and shall only apply to Member. As such, Member shall make payment for electric service under the Agreement through the rates and Fixed Charge established by AEPCO in accordance with the Agreement and this Rate Schedule A. As a Partial Requirements Member, Member shall remain obligated at all times during the term of the Agreement, including periods in which a Force Majeure has been declared, to pay its Fixed Charge and O&M charge as determined in accordance with this Rate Schedule A.

2.2 Power Factor and Demand Overrun Adjustments.

If the Power Factor of Member measured at such Member's Delivery Point(s) at the time of Member peak demand is outside a bandwidth of 90% leading to 90% lagging (the bandwidth shall be 95% leading to 95% lagging as of January 1, 2005, provided that a similar change in bandwidth is made effective for all Class A Members), a Power Factor Adjustment shall be separately charged to such Member. The Power Factor Adjustment shall be the product of a power factor adjustment (as set forth below) multiplied by the O&M rate. The power factor adjustment shall be any non-negative number determined from the following formula:

$$pfakW = ((mkW / mpf)(bpf)) - mkW$$

Where:

pfakW = power factor adjustment in kW; and
mkW = Member Metered kW, and
mpf = measured power factor at the time of Member peak demand, and
bpf = 0.90 prior to January 1, 2005, and 0.95 thereafter.

In addition, if the Member Billing Demand for the Partial Requirements Member exceeds its Allocated Capacity, then Partial Requirements Member shall also be separately charged a Demand Overrun Adjustment. Such Demand Overrun Adjustment shall equal the product of the Fixed Charge multiplied by the demand overrun adjustment factor. The demand overrun adjustment factor shall be any non-negative number determined from the following formula:

$$doaf = ((mbdkW) / AC) - 1$$

Where:

doaf = demand overrun adjustment factor
mbdkW = Member Billing Demand in kW, and
AC = Allocated Capacity of Member, in kW.

The Power Factor Adjustment and the Demand Overrun Adjustment, as set forth at the levels of take established in Schedule B, to the extent applicable, shall be added to the monthly bill for payment by the Member in addition to the rates and Fixed Charge for capacity and energy sales.

2.3 Stranded Cost Recovery.

AEPCO's Stranded Costs, as may be authorized to be recovered under applicable Law, shall include and currently consist of a Competitive Transition Charge (CTC) and a Regulatory Asset Charge (RAC). The rates and Fixed Charge specified in Exhibit A-1 shall be adjusted to include a stranded cost recovery charge reflecting the recovery of AEPCO's Stranded Costs. Bills rendered under the terms of this Rate Schedule A shall include charges for any Stranded Costs that AEPCO may be authorized to recover under applicable Law and Member is authorized under applicable Law and able to collect. Such Stranded Cost charges shall be separately itemized as specified in Exhibit A-4 hereof. AEPCO's CTC and RAC shall be added to the Member's monthly bill, for collection and payment by the Member in addition to the rates and Fixed Charge for capacity and energy sales. The Member shall collect all such funds which it is authorized under applicable Law and able to collect and remit to AEPCO those funds as specified in Section 3.6 hereof. The CTC shall apply only to energy competitively supplied by non-parties to individual customers within the Member's Distribution Service Area, while the RAC shall apply to all energy sold in the Member's Distribution Service Area, or as otherwise ordered by applicable Law. AEPCO's right to recover the RAC has been assigned to TRANSCO pursuant to the Restructuring Agreement, therefore, TRANSCO may bill and Member shall pay the RAC directly to TRANSCO.

2.4 Taxes and/or Assessments.

The rates and Fixed Charge set forth in Exhibit A-1 to Rate Schedule A herein do not include sales taxes, transaction privilege taxes or regulatory assessments or similar governmental impositions which are, or may in the future be, levied on AEPCO by any Governmental Authority having jurisdiction and which are not included in the AEPCO Revenue Requirement used to develop the rates and Fixed Charge. Therefore, bills rendered under the terms of this Rate Schedule A shall include all such federal, state and local sales taxes, transaction privilege taxes, assessments or similar governmental impositions. Such taxes and/or assessments shall be itemized and added to the bill in addition to the rates and Fixed Charge for capacity and energy sales for payment by the Member.

2.5 Charges.

The monthly charge billed to the Partial Requirements Member in accordance with Section 5.1 of the Agreement and as provided for in applicable provisions of Section 5 of the Agreement, shall consist of the following:

1. the Fixed Charge as set forth in Exhibit A-1 hereof; plus,

2. the O&M charge, which shall be the product of the O&M rate set forth in Exhibit A-1 hereof multiplied by the Member Billing Demand; plus,

3. the energy charge, which shall be the product of the energy rate set forth in Exhibit A-1 hereof multiplied by the Member Billing Energy; plus

4. any Power Factor and Demand Overrun Adjustments pursuant to Section 2.2 hereof; plus,

5. any Stranded Cost recovery pursuant to Section 2.3 hereof; plus

6. all taxes and/or assessments pursuant to Section 2.4 hereof, if any; plus

7. any charges incurred pursuant to Schedule B to this Agreement; plus

8. the separate charge for the portion of Member's AC attributable to the purchase power agreement between Panda Gila River L.P. and AEPCO, dated April 15, 2003, as amended (the "PGR PPA"), as such charge is set forth in Appendix A to Exhibit A-1 to this Rate Schedule A (the "SSVEC PGR PPA Charge").

2.6 Sample Bill.

A form of bill which sets forth for illustrative purposes rates, charges and adjustments to be made by AEPCO to Member pursuant to this Agreement, including this Rate Schedule A is attached as Exhibit A-4 to this Rate Schedule A. Actual billings made by AEPCO to Member pursuant to Section 5.1 of this

Agreement shall be substantially in the form of, and contain the information set forth in, such sample bill.

3. RATE DEVELOPMENT:

3.1 Rate Administration.

The Board of Directors of AEPCO shall review the level of revenues generated by the rates and Fixed Charges set forth in Exhibits A-1 to Rate Schedules A and revenues generated from other rates and charges to the Class A Members, together with revenues generated from all other sources, to determine their sufficiency to meet AEPCO's Revenue Requirement. In the event that the rates and Fixed Charges as set forth in Exhibits A-1 to Rate Schedules A do not provide revenues sufficient, but only sufficient, to satisfy AEPCO's Revenue Requirements From Partial Requirements Members, the Board of Directors of AEPCO shall establish new rates and new Fixed Charges, for electric service to the Partial Requirements Members pursuant to the procedures set forth in Section 5.6 of the Agreement and otherwise comply with those provisions pertaining to rates and the Fixed Charge as set forth in Section 5 of the Agreement. Such new rates and Fixed Charges established in conjunction with new rates for the All Requirements Members shall be submitted to the RUS and shall become effective unless they have been disapproved in writing by the RUS and Exhibits A-1 (and other Exhibits, as may be applicable) to Rate Schedules A shall be modified to reflect the new rates and Fixed Charges in effect.

3.2 Development of Cost of Service and Revenue Requirement.

AEPCO rates and the Fixed Charge developed under this Rate Schedule A charged to its Partial Requirements Member and rates and charges to the other Class A Members shall be based upon AEPCO's Revenue Requirement and cost of service studies utilizing a twelve-month test period ending not more than six months before such cost of service studies are first considered by AEPCO. Accounting data for such test period shall be taken from the books and records of AEPCO.

The test period data for the cost of service studies shall be adjusted to reflect known and measurable changes to expenses and billing determinants that have occurred during the test period and/or are expected to continue to occur after the test period (i.e. normalized for the test period). The cost of service studies may also be normalized for changes that are known and measurable which will occur after the test period (out of period changes).

The fixed, O&M and energy components of AEPCO's Revenue Requirement From Partial Requirements Members shall be developed from fixed, O&M and energy components of AEPCO's Revenue Requirement From AEPCO's Class A Members pursuant to Exhibit A-2 to this Rate Schedule A.

3.3 Classification of Expenses.

The expenses and revenue credits, included in the cost of service studies shall be classified as fixed, O&M, and/or energy as set forth in Exhibit A-2 and depicted in Exhibit A-3 hereto.

3.4 Development of Rates and the Fixed Charge, Billing Determinants.

Once the components of fixed, O&M, and energy for AEPCO's Revenue Requirement From Partial Requirements Members are determined pursuant to Section 3.2, and all expenses are classified pursuant to Section 3.3, the rates and the Fixed Charge to be charged pursuant to the Agreement shall be determined in accordance with Exhibit A-2. The billing determinants for the Fixed Charge shall be the ACP as specified in Section 3.5 below. The billing determinants for the O&M and energy rates shall be as set forth in Sections 5.3 and 5.4 of Exhibit A-2, respectively.

3.5 Allocated Capacity Percentage (ACP) and Allocated Capacity (AC).

Appendix A to Exhibit A-5 sets forth the Allocated Capacity Percentages (ACP) that shall be used to develop the Fixed Charge for the Partial Requirements Member and the SSVEC PGR PPA Charge. Appendix B to Exhibit A-5 to this Rate Schedule A identifies the AEPCO Existing Resources as well as the Allocated Capacity (AC) for the Partial Requirements Member.

3.6 Stranded Cost Recovery Charges.

Revenue received by the Partial Requirements Member to recover AEPCO's Stranded Costs as authorized by the ACC shall be remitted and paid to AEPCO as provided for hereunder. Such revenues anticipated to be remitted to AEPCO shall be treated in AEPCO's annual cost of service studies as revenue generated from sources other than the Class A Members and shall be credited as set forth in Exhibit A-2. The Partial Requirements Member shall collect and remit to AEPCO (or to TRANSCO as set forth in Section 2.3 hereof) all revenues resulting from the imposition of the RAC on all energy sold in the Member's Distribution Service Area, as authorized by the ACC. The Partial Requirements Member shall collect and remit to AEPCO a portion of the total revenues resulting from the imposition of the CTC on energy competitively supplied by non-parties to individual customers within the Member's Distribution Service Area. Such portion of the revenues resulting from such imposition of the CTC which shall be remitted to AEPCO shall equal the amount obtained by multiplying the total revenue so collected by the Partial Requirements Member pursuant to such imposition of the CTC by a ratio obtained by dividing the then current O&M component by the sum of the fixed charge component and the O&M component (all as determined pursuant to Exhibit A-2 hereof), or as otherwise required by the ACC.

Exhibit A-1 to Rate Schedule A

Partial Requirements Member
Rates and Fixed Charge
(Effective as of Agreement Date)

Fixed Charge Sulphur Springs Valley Electric Cooperative, Inc.	$700,095 per month *
O&M Rate	$7.15 per kW/month *
Energy Rate	$0.02073 per kWh * used during the billing period.
Base Energy Charge for FFPAC	$0.01603 per kWh *

*estimated based on 2003 test year data with pro forma adjustments as approved by the ACC in August 2005.

NOTE: THE RATES AND FIXED CHARGE SHALL BE ADJUSTED FURTHER FOR ANY POWER FACTOR ADJUSTMENT, DEMAND OVERRUN ADJUSTMENTS, STRANDED COST RECOVERY, AND TAXES AND/OR ASSESSMENTS, PURSUANT TO SECTIONS 2.2, 2.3, AND 2.4, RESPECTIVELY, AND ANY ADJUSTMENTS RESULTING FROM SCHEDULE B OF THE AGREEMENT.

APPENDIX A TO EXHIBIT A-1

SSVEC PGR PPA CHARGE

YEAR	MONTHLY COST CALCULATIONS — PGR PPA Deliveries, May thru Sept: Westwing	Palo Verde	Total	$0.41 kW- Mo EPE Wheel for PV Delivery Cost (2) $	Total May to Sept AEPCO Monthly PGR PPA CHARGE $	SSVEC ACP for PGR PPA %	Total May to Sept **Monthly SSVEC PGR PPA CHARGE** $	Total Annual SSVEC PGR PPA CHARGE $
2004								
Demand in kW	40,000	0	40,000					
Rate in $ per kW	$6.94	$0.00						
Total Monthly Charge $	$ 277,600	$ -	$ 277,600	$ -	$ 277,600	49.40%	$ 137,134	$ 685,672
2005								
Demand in kW	10,000	50,000	60,000					
Rate in $ per kW	$6.94	$4.84						
Total Monthly Charge $	$ 69,400	$ 242,000	$ 311,400	$ 20,500	$ 331,900	49.40%	$ 163,959	$ 819,793
2006								
Demand in kW	25,000	50,000	75,000					
Rate in $ per kW	$6.94	$4.84						
Total Monthly Charge $	$ 173,500	$ 242,000	$ 415,500	$ 20,500	$ 436,000	49.40%	$ 215,384	$ 1,076,920
2007								
Demand in kW	35,000	50,000	85,000					
Rate in $ per kW	$6.94	$4.84						
Total Monthly Charge $	$ 242,900	$ 242,000	$ 484,900	$ 20,500	$ 505,400	49.40%	$ 249,668	$ 1,248,338

NOTES:

(1) September's monthly charge each year shall be adjusted to account for SSVEC's 49.4% share of any Capacity Payment Adjustment payable to or by AEPCO pursuant to the PGR PPA.

(2) AEPCO purchases wheeling from El Paso Electric Company pursuant to a service agreement under EPE's OATT to enable AEPCO's receipt at Palo Verde of PGR PPA power, which enables the $2.10 per kW reduction in PGR PPA demand charges.

Exhibit A-2 to Rate Schedule A
Development of Rates and Fixed Charge

1.0 INTRODUCTION:

This Exhibit A-2 specifies the methodology for the development of rates and the Fixed Charge applicable for Resources in which Member has an ACP. This methodology shall be applied to AEPCO expenses and revenues described herein which are maintained under the Uniform System of Accounts and classified as (a) fixed, (b) O&M, or (c) energy. All amounts described hereunder and included in such accounts shall be those amounts recorded in AEPCO's financial records for the test period used in the applicable cost of service study from which the rates and Fixed Charge are to be developed. Such amounts when adjusted for appropriate credits and normalized with appropriate adjustments are the AEPCO costs and expenses which shall be used as the basis for the cost of service which determines AEPCO's Revenue Requirement which is the sum of: (i) revenues to be recovered from the Partial Requirements Member through charging the rates applied to its Member Billing Demand and Member Billing Energy and Fixed Charge pursuant to its Partial Requirements Capacity and Energy Agreement, plus (ii) revenues to be recovered from other Partial Requirements Members through charging rates pursuant to their Partial Requirements Capacity and Energy Agreements; plus (iii) revenues to be recovered from the All Requirements Members through charging rates pursuant to their Existing Wholesale Power Contracts, plus (iv) AEPCO revenues from all other sources.

2.0 CLASSIFICATION OF EXPENSES AND REVENUES:

2.1 Classifications.

For purposes of this Exhibit A-2 to Rate Schedule A, classifications shall be made of the AEPCO expenses and revenues from sources other than sales to AEPCO Class A Members and maintained and identified using the Uniform System of Accounts, for the purpose of identifying such expenses as either: (a) fixed (F), (b) Operations and Maintenance (O&M) (O), or(c) energy (E), as follows:

(The account numbers refer to accounts maintained by AEPCO under the Uniform System of Accounts in its financial records.)

Amounts in Accounts 500 through 554, with the exception of Accounts 501 and 547, shall each be classified as Production-O (consisting of operations and maintenance expenses related to steam and other power generation).

Amounts in Accounts 501 and 547 shall be separated and classified either as: Fuel-F (consisting of O&M and amortization expenses relating to the Carbon Coal Company investment and gas transportation reservation charges), or as Fuel-E (consisting of remaining Accounts 501 and 547 Expenses).

Amounts in Accounts 555 shall be separated and classified as: Purchased Power-F (capacity or demand charges), Purchased Power-O (O&M related charges), or as Purchased Power-E (energy charges).

Amounts in Accounts 556 and 557 shall be classified as: Other Power Supply-O (System Control, dispatching and O&M charges).

Amounts in Account 565 shall be separated and classified as: Wheeling Expense-O (consisting of firm wheeling charges), or as and Wheeling Expense-E (consisting of non-firm wheeling charges).

Amounts in Accounts 901-916, which consist of consumer accounts, customer accounts and sales expense, shall be classified as Customer-O.

Based on the respective ratios of labor expenses in (a) Steam Power Generation (Accounts 500-507 and 510-514) and Other Power Production (Accounts 546-554) and (b) Other Power Supply (Accounts 556 and 557), compared to the sum of all such labor expenses, the amounts in Accounts 920-923 and 927-932 shall each be separated and classified as either: (a) Administrative & General I-O, or as (b) Administrative & General I-E.

Based on the portions of Production Plant (Accounts 300-316) and General Plant (Accounts 389-399) respectively associated with (a) fixed, (b) O&M, and (c) energy, compared to the sum of such expenses, the amounts in Account 924 shall be respectively separated and classified as either: (a) Administrative & General II-F, (b) Administrative & General II-O, or as (c) Administrative & General II-E.

Based on the respective ratios of labor expenses in (a) Steam Power Generation (Accounts 500-507 and 510-514) and Other Power Production (Accounts 546-554), (b) Other Power Supply (Accounts 556 and 557), (c) Sales Expense (Accounts 911-916) and (d) Administrative and General (Accounts 920-923 and 927-932), compared to the sum of such labor expenses, the amounts in Accounts 925 and 926 shall each be separated and classified as either: (a) Administrative & General III-O, or as (b) Administrative & General III-E.

The revenue amounts in Accounts 447-456 shall be first aggregated into credits and then separated based upon the following calculus and classified as either: (a) Credits-F, (b) Credits-O, or as (c) Credits-E. The portion of such credits corresponding to the product resulting from the multiplying: (a) AEPCO average system energy cost of producing electricity, by: (b) AEPCO's kWh sales to other than AEPCO's Class A Members shall be classified as Credits-E. The remainder of such credits shall be classified as Credits-F and Credits-O based upon a pro rata dollar division of such credits based upon the amount of expenses assigned to the fixed and O&M categories compared to the sum of such expenses.

Margins shall be classified and assigned to the fixed category.

2.2 Depiction.

The expense and revenue accounts, their classification into fixed, O&M and energy, and the adjustments specified in this Exhibit A-2 are depicted in tabular form in Exhibit A-3.

3.0 FIXED CAPACITY AND O&M COMPONENT:

3.1 Purpose and Elements.

The purpose of this Section 3.1 and Sections 3.2 and 3.3 hereof is to set forth the methodology for the development of the rates and Fixed Charges attributable to electric service under the Partial Requirements Capacity and Energy Agreements. The fixed capacity component and the O&M component shall be used to calculate and determine the Fixed Charges as provided in Section 5.2 hereof, and the O&M rates as provided in Section 5.3 hereof.

3.2 Fixed Capacity Component.

The fixed capacity component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as fixed, as applicable pursuant to Section 2 hereof, to the extent attributable to the AEPCO Resources in which Member has an ACP:

Account 403	(Depreciation & Amortization Expense),
Account 408	(Ad Valorem Taxes),
Accounts 427-428	(Interest on Long Term Debt, Interest Charged to Construction, Other Interest Expense, and Other Deductions),
Account 501	(Fuel-F only),
Account 547	(Fuel-F only)
Account 555	(Purchased Power - F only, excluding the demand charge associated with the PGR PPA otherwise included in the SSVEC PGR PPA Charge.)
Account 924	(Administrative & General II-F only), and Margin in an amount sufficient to assure AEPCO of, at a minimum, a reasonable level of working capital and maintenance of annual coverage ratios, or any other financial covenants or tests prescribed or imposed by RUS or any other applicable Financial Entities,
less Accts 447-456	(Credits-F only, including recovery of AEPCO's Competitive Transition Charge from the All Requirements Members to be allocated to fixed costs in Account 451, or its successor account in the ratio obtained by dividing the fixed component of the revenue requirement by the sum of such fixed component plus the O&M component of the revenue requirement).

3.3 O&M Component.

The O&M component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as O&M, as applicable pursuant to Section 2 hereof, to the extent attributable to the AEPCO Resources in which Member has an ACP:

Accounts 500-554, except for Accounts 501 and 547 (Production-O only),

Account 555	(Purchased Power-O only)
Accounts 556 and 557	(Other Power Supply-O only),
Account 565	(Wheeling Expense-O only),
Accounts 901-916	(Customer-O only),
Accounts 920-923	(Administrative & General I-O only), 924 (Administrative & General II-O only), 925-926 (Administrative & General III-O only), and 927-932 (Administrative & General I-O only),
Less Accts 447-456	(Credits-O only, including recovery of AEPCO's Competitive Transition Charge from both Partial Requirements Members and the All Requirements Members to be allocated to O&M costs in Account 451, or its successor account in the ratio set forth in Section 3.6 of this Rate Schedule A.)

4.0 ENERGY COMPONENT:

The energy component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as energy, as applicable, pursuant to Section 2 hereof, to the extent attributable to the AEPCO Resources in which Member has an ACP:

Accounts 501 and 547	(Fuel-E only, including all energy charges of the PGR PPA),
Accounts 555	(Purchased Power-E only),
Account 565	(Wheeling Power-E only), and
Accounts 920-923	(Administrative & General I-E only), 924 (Administrative & General II-E only), 925-926 (Administrative & General III-E only), and 927-932 (Administrative & General I-E only),
Less Accounts 447-456	(Credits-E only, including recovery of AEPCO's Competitive Transition Charge to be recorded in Account 451, or its successor account).

5.0 PARTIAL REQUIREMENTS MEMBER RATES AND FIXED CHARGE:

5.1 Elements.

The rates and Fixed Charge for electric service under the Agreement to the Partial Requirements Member shall consist of (a) the Fixed Charge, composed of an appropriate allocated fixed capacity component, including a margin, (b) an O&M rate, (c) an energy rate, and (d) the SSVEC PGR PPA Charge.

5.2 Fixed Charge.

The monthly Fixed Charge for the Partial Requirements Member, stated in dollars, shall equal: (a) the expenses less revenue credits used to determine the current fixed capacity component in Section 3.2 of this Exhibit A-2, and shall include prior period losses (negative equity) resulting from deficiencies or shortfalls incurred up to the Agreement Date from failures of Members to meet their portion of AEPCO's Revenue Requirement, (b) multiplied by the ACP for the Partial Requirements Member, and (c) divided by twelve (12) to convert to a monthly charge.

5.3 O&M Rate.

The O&M rate for the Partial Requirement Member shall equal the O&M component comprised of the expenses, less revenue credits as calculated in Section 3.3 of this Exhibit A-2, divided by the aggregate test year demand billing units (stated in kW) developed in the cost of service study for the Class A Members. With respect to Partial Requirements Member, such demand billing units shall consist of the annualized Member Billing Demand of the test period, adjusted for known and measurable changes.

5.4 Energy Rate.

The energy rate for the Partial Requirements Member shall equal the energy component comprised of the expenses (which expenses shall include the energy charges of the PGR PPA until otherwise mutually agreed), less revenue credits as calculated in Section 4.0 of this Exhibit A-2, divided by the aggregate test year energy billing units (stated in kWh) developed in the cost of service study for the Class A Members. With respect to Partial Requirements Member, such energy billing units shall consist of the annualized Member Billing Energy of the test period, adjusted for known and measurable changes.

5.5 SSVEC PGR PPA Charge.

The SSVEC PGR PPA Charge shall be the additional monthly charge in May through September of each year through 2007 as set forth in Appendix A to Exhibit A-1 hereto and shall consist of the product of: (i) SSVEC's ACP set forth in Section B of Appendix A to Exhibit A-5 hereto; multiplied by (ii) in May through September of each year through 2007, the sum of (a) the monthly demand charge billed to AEPCO under the PGR PPA, plus (b) the monthly transmission charge billed to AEPCO by El Paso Electric Company pursuant to the Service Agreement between AEPCO and EPE, dated July 3, 2003.

6.0 REVENUE SHORTFALLS:

Any deficiencies or shortfalls in collections of AEPCO's Revenue Requirement From Partial Requirements Members will be recovered through appropriate adjustments to: (a) the O&M rates, or (b) the margin included in the Fixed Charges for Partial Requirements Members. An adjustment will be made to the O&M rate to the extent such deficiencies or shortfalls are attributable to the collection of revenues for operations and maintenance expenses. An adjustment will be made to the margin included in the Fixed Charge for all other such deficiencies or shortfalls. Such deficiencies or shortfalls may also be recovered through a combination of appropriate adjustments to the O&M rate or the margins.

7.0 NO ADJUSTMENT FOR TRANSMISSION LOSSES:

The billing determinants included in the cost of service study and used to develop and implement the rates and Fixed Charge shall be as metered at the Delivery Points after transmission losses. Consequently, AEPCO's Revenue Requirement developed as a result of such cost of service study reflects the costs of generating or acquiring sufficient capacity and energy to cover transmission losses. Therefore, the rates developed as set forth herein implicitly encompass recovery of the costs associated with transmission losses and there is no need for a separate adjustment for transmission losses.

Exhibit A-3 to Rate Schedule A

Classification of Expenses

Uniform System Account No.	Description	Fixed Expenses (F)	O&M Expenses (O)	Energy Expenses (E)
	Production and Other Power Supply			
	Steam Power Generation:			
	Operation:			
500	Operation Supervision & Engineering		X	
501	Fuel	X(1)		X(1)
502	Steam Expenses		X	
505	Electric Expenses		X	
506	Miscellaneous Steam Power Expenses		X	
507	Rents		X	
	Maintenance:			
510	Supervision & Engineering		X	
511	Structures		X	
512	Boiler Plant		X	
513	Electric Plant		X	
514	Miscellaneous Steam Plant		X	
	Other Power Generation:			
	Operation:			
546	Operation Supervision & Engineering		X	
547	Fuel	X(1)		X(1)
548	Generation Expenses		X	
549	Miscellaneous Other Power Generation		X	
550	Rents		X	
	Maintenance:			
551	Supervision & Engineering		X	
552	Structures		X	
553	Generating and Electric Equipment		X	

[1]All fuel related costs are assigned to the energy classification, except for Carbon Coal Company O&M expense and amortization of investment and gas transportation reservation charges which are assigned to the fixed classification because they do not pertain to fuel commodity costs.

Uniform System Account No.	Description	Fixed Expenses (F)	O&M Expenses (O)	Energy Expenses (E)
554	Miscellaneous Other Power Generation		X	
	Other Power Supply Expenses:			
555	Purchased Power	X[(2)]	X[(2)]	X[(2)]
556	System Control & Load Dispatching		X	
557	Other Expenses		X	
565	Wheeling Expense		X[(3)]	X[(3)]
901-905	Consumer Accounts		X	
906-910	Customer Service & Information		X	
911-916	Sales Expense		X	
	Administrative & General:			
920	Salaries		X[(4)]	X[(4)]
921	Office Supplies & Expenses		X[(4)]	X[(4)]
922	A&G Expenses Transferred Credit		X[(4)]	X[(4)]
923	Outside Services		X[(4)]	X[(4)]
924	Property Insurance	X[(5)]	X[(5)]	X[(5)]
925	Injuries & Damages		X[(6)]	X[(6)]
926	Employee Pensions & Benefits		X[(6)]	X[(6)]
927	Franchise Requirements		X[(4)]	X[(4)]

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[2]Purchased power, capacity or demand charges are assigned to the fixed classification, any O&M charges to the O&M classification and energy charges and interchange expenses are assigned to the energy classification.

[3]Firm wheeling charges are assigned to the O&M classification and non-firm wheeling charges are assigned to the energy classification.

[4]Administrative and general expenses are assigned to the O&M and energy classifications based upon the distribution of production and other power supply labor expenses to the O&M and energy classifications.

[5]Assigned to the fixed, O&M and energy classifications based upon the distribution of production and general plant between classifications.

[6]Assigned to the O&M and energy classifications based upon the distribution of total labor expenses to the O&M and energy classifications.

Uniform System Account No.	Description	Fixed Expenses (F)	O&M Expenses (O)	Energy Expenses (E)
928	Regulatory Commission Expenses		X(4)	X(4)
929	Duplicate Charges Credit		X(4)	X(4)
930	Miscellaneous General Expense		X(4)	X(4)
931	Rents		X(4)	X(4)
932	Maintenance of General Plant		X(4)	X(4)
403	Depreciation & Amortization Expense	X		
408	Ad Valorem Taxes	X		
	Interest & Other Deductions:			
427	Interest on Long Term Debt	X		
427	Interest Charged to Construction	X		
427	Other Interest Expense	X		
428	Other Deductions	X		
447-456	Operating Revenues from Other Sources – Credit	X(7)	X(7)	X(7)
	Margin Component	X		

[7] Revenue from sources other than AEPCO's Class A Members is assigned to the energy classification on the basis of AEPCO average cost of energy multiplied by kWh sales from such other sources. The remainder of such revenue including recovery of AEPCO's Stranded Costs is assigned to the fixed and O&M classifications on a pro-rata basis as set forth in Section 3.6 of this Rate Schedule A and Exhibit A-2, Sections 3.2 and 3.3hereof, as applicable.

Exhibit A-4 to Rate Schedule A

SAMPLE INVOICE

TO: SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
POST OFFICE BOX 820
WILLCOX, ARIZONA 85643

ATTN: Creden Huber, Chief Executive Officer

DATE: September 2, 2004

PARTIAL REQUIREMENTS CAPACITY AND ENERGY INVOICE w/ Supplemental

AUGUST, 2004

Schedule A Demand Charges		$1,719,260.82
Schedule A Energy Charges	$	1,326,702.44
Schedule B Demand Charges		$0.00
Schedule B Energy Charges		$203,233.22
Supplemental Demand Charges:	$	-
Supplemental Energy Charges:	$	(124,324.02)
Stranded Cost Recovery Competitive Transition Charge (CTC)		$0.00
ACC Gross Operating Revenue Assessment		$6,249.74
SUBTOTAL DUE AEPCO	$	3,131,122.20
Less: Power Prepayment Program (see attached detail)		$0.00
AMOUNT DUE TO ARIZONA ELECTRIC POWER COOPERATIVE, INC.	$	3,131,122.20

PLEASE WIRE PAYMENT TO:
Bank of America Phoenix, AZ
ABA # 122101706 ACCT# 412-724519
C/O BLANCHE MCCUNE-FINANCIAL SERVICES
P.O. BOX 670
BENSON, AZ 85602-0670

Payments are due in respective offices the later of 10 days after receipt or September 20, 2004. Payments not received by September 20, 2004 shall accrue interest at the contract rate of interest.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

IN ACCOUNT WITH:
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
POST OFFICE BOX 820
WILLCOX, ARIZONA 85643

BILLING PERIOD: August, 2004

DATE: September 2, 2004 DATE DUE: September 20, 2004

DESCRIPTION				CREDITS	CHARGES
SCHEDULE A DEMAND CHARGES					
FIXED CHARGE for EXISTING RESOURCES		$ 624,964.00	Fixed		
FIXED CHARGE for PGR PPA		$137,134.40	Fixed		
TOTAL FIXED CHARGE for ALLOCATED CAPACITY	142,300 kW @	$ 762,098.40	Fixed		$ 762,098.40
MEMBER BILLING DEMAND	131,298 kW @	$7.29			$ 957,162.42
AC DEMAND OVERRUN	0.000% X	$ 762,098.40			$ -
POWER FACTOR CONTRIBUTION	0 kW @	$7.29	/kW		$ -
	SCHEDULE A DEMAND SUBTOTAL:			$ -	$ 1,719,260.82
SCHEDULE A ENERGY CHARGES					
MEMBER BILLING ENERGY (Schedule A)	64,061,450 kWh @	$0.020710	/kWh		$ 1,326,712.63
MEMBER BILLING ADJ for METERED LOAD	(492) kWh @	$0.020710	/kWh	$ 10.19	$ -
FUEL ADJUSTMENT	64,060,958 kWh @	$0.000000	/kWh		$ -
	SCHEDULE A ENERGY SUBTOTAL:			$ 10.19	$ 1,326,712.63
SCHEDULE B DEMAND CHARGES					
HIGHEST DEMAND OVERRUN	0 kW @	$13.79	/kW		$ -
MINIMUM DEMAND FOR O&M	0 kW @	$7.29	/kW		$ -
	SCHEDULE B DEMAND SUBTOTAL:			$ -	$ -
SCHEDULE B ENERGY CHARGES					
ENERGY & ENERGY OVERRUNS	3,810,198 kWh @	$0.053339	/kWh		$ 203,233.22
ENERGY MINIMUMS	0 kWh @	$0.000000	/kWh		$ -
					$ -
	SCHEDULE B ENERGY SUBTOTAL:			$ -	$ 203,233.22
SUPPLEMENTAL CAPACITY & ENERGY AGREEMENT (1)					
DEMAND:					
SUPPLEMENTAL BILLING DEMAND	0 kW @	$13.79			$ -
SUPPLEMENTAL O&M CREDIT	0 kW @	$7.29		$ -	
SUPPLEMENTAL AC DEMAND OVERRUN CREDIT	0.000% X	$ 762,098.40		$ -	
SCH B HIGHEST DEMAND OVERRUN CREDIT	0 kW @	$13.79	/kW	$ -	
SCH B MINIMUM DEMAND FOR O&M CREDIT	0 kW @	$7.29	/kW	$ -	
ENERGY:					
SUPPLEMENTAL BILLING ENERGY	0 kWh @	$0.020710	/kWh		$ -
SCH B Member Billing Energy Billed as Sch A	3,810,198 kWh @	$0.020710	/kWh		$ 78,909.20
SCH B ENERGY & ENERGY OVERRUNS CREDIT	3,810,198 kWh @	$0.053339	/kWh	$ 203,233.22	
FUEL ADJUSTMENT	3,810,198 kWh @	$0.000000	/kWh		$ -
SCH B ENERGY MINIMUMS CREDIT	0 kWh @	$0.000000	/kWh	$ -	
	SUPPLEMENTAL CONTRACT SUBTOTAL:			$ 203,233.22	$ 78,909.20
NOTES: (1) Billed pursuant to Supplemental Capacity and Energy Agreement through December 31, 2005.					
STRANDED COST RECOVERY					
COMPETITIVE TRANSITION CHARGES (CTC)	0 kWh @	0	/kWh		$ -
FIXED CHARGE PORTION RETAINED	0 @	67.87%			$ -
ACC GROSS OPERATING REVENUE ASSESSMENT	**STRANDED COST SUBTOTAL:**				$ -
	$ 3,124,872.46 X	0.200%			$ 6,249.74
	SUBTOTAL			$ 203,243.41	$ 3,334,365.61
TOTAL AMOUNT PAYABLE TO AEPCO					$ 3,131,122.20

IN ACCOUNT WITH:
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
POST OFFICE BOX 820
WILLCOX, ARIZONA 85643

SAMPLE INVOICE

BILLING MONTH: **AUGUST, 2004**

DATE: September 2, 2004

DATE DUE: September 20, 2004

POWER FACTOR ADJUSTMENT: $\frac{\text{KW}}{\text{POWER FACTOR}}$ X .9	METERED kW	POWER FACTOR	ADJUSTED KW	POWER FACTOR ADJUST
	0	0	0	0
	0	0	0	0
	0	0	0	0
	0	0	0	0
	0	0	0	0
	0	0	0	0
TOTAL POWER FACTOR ADJUSTMENT:				0

SSVEC PEAK:

139.160 MW on 8/11/2004 @ 12:30

IN ACCOUNT WITH:

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
POST OFFICE BOX 820
WILLCOX, ARIZONA 85643

SAMPLE INVOICE

BILLING MONTH: **AUGUST, 2004**

DATE: September 2, 2004

Prepay Date	Due Date	Prepay Amount	Interest Rate	Days Invested	Daily Accrued Interest	Interest Earned	Total Prepayment + Interest
					$0.00	$0.00	$ -
					$0.00	$0.00	$ -
					$0.00	$0.00	$ -
TOTAL							$0.00

IN ACCOUNT WITH:

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE
POST OFFICE BOX 820
WILLCOX, ARIZONA 85643

BILLING PERIOD: August, 2004

DATE: September 2, 2004

METERING POINT	PRESENT READING	PREVIOUS READING	DIFF.	MULT.	kWh	kW	ADJUST FACTOR	kWh FOR BILLING	kW FOR BILLING
REDTAIL / STEWART OUT	6697841	490560	6207281	1	6,207,281	9,898			
BOWIE OUT	4572065	828316	3743749	1	3,743,749	4,221			
REDTAIL TOTAL OUT								9,951,030	14,119
STEWART OUT (FROM GCEC)	8226	8226	0	10				0	0
MORTENSON OUT	595747	410698	185049	10	1,850,490	2,960	1.019	1,885,649	3,016
BONITA OUT	5236097	3079568	2156529	1	2,156,529	3,120	1.019	2,197,503	3,179
KARTCHNER OUT	235592	82215	153377	100				15,337,700	31,000
WILLCOX OUT	304780	268083	36697	100	3,669,700	7,800			
KANSAS SETTLEMENT OUT	925317	847487	77830	100	7,783,000	10,200			
JOHNSON OUT	1021441	913126	108315	100	10,831,500	22,800			
APACHE TOTAL OUT								22,284,200	40,800
HAWES OUT	8866968	163500	8703468	1	8,703,468	20,210			
PUEBLO OUT	9790503	2028149	7762354	1	7,762,354	16,098			
RAMSEY OUT	5488638	708254	4780384	1	4,780,384	10,826			
SAN RAFAEL TOTAL OUT								21,246,206	47,134
REDTAIL / STEWART IN	197565	197565	0	1	0	0			
BOWIE IN	0	0	0	10	0	0			
REDTAIL TOTAL IN								0	0
STEWART IN (TO GCEC)	506148	10477	495671	10	4,956,710	7,840	1.014	(5,026,104)	(7,950)
MORTENSON IN	24867	24867	0	10				0	0
BONITA IN	24726	24726	0	1				0	0
KARTCHNER IN	161	161	0	100				0	0
WILLCOX IN	35468	35468	0	100	0	0			
KANSAS SETTLEMENT IN	1244	1244	0	100	0	0			
JOHNSON IN	160	160	0	100	0	0			
APACHE TOTAL IN								0	0
HAWES IN	4603762	4603762	0	1	0	0			
PUEBLO IN	1515991	1515991	0	1	0	0			
RAMSEY IN	467	467	0	1	0	0			
SAN RAFAEL TOTAL IN								0	0
MCNEIL TO SSVEC	1687	1687	0	1000	0	0	1.08	0	0
MCNEIL TO APS	3628	3628	0	1000	0	0	1.09	0	0
STEWART IN (TO GCEC)					4,959		1.014	(5,028)	
							TOTAL	67,871,156	131,298
LESS SCHEDULES FROM COMPETITIVE SUPPLIERS:									
				COMPETITIVE SCHEDULE TOTAL				0	0
TOTAL								67,871,156	131,298

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
SCHEDULE A DEMAND OVERRUN AND MINIMUM O&M DEMAND SUMMARY rpk
SAMPLE INVOICE
AUGUST, 2004

							AEPCO PEAK						
				A	B	C A+B	D	E D-E	F	G E-F			H G - ALLOC CAP
DAY	DAY OF WEEK	TIME	DATE OF AEPCO BILLING PEAK *	SSVEC METERED LOAD AT AEPCO COINCIDENTAL PEAK MW	SSVEC AEPCO SALES MW	TOTAL MW	RESOURCE SCHEDULE for SSVEC WHEELING (MEMBER JMP & CSP JMP) MW	LOAD for AEPCO & MEMBER RESOURCES MW	MEMBER RESOURCE SCHEDULE for SSVEC INTERNAL LOADS MW	AEPCO RESOURCE USED MW	SSVEC BILLING DEMAND MW	(1) AEPCO RESOURCE above AC (Rate Sched A) MW	ADDITIONAL DEMAND for MIN O&M CHARGE MW
1	SU	14:00		111.397	0.000	111.397	0.0	111.397	0.0	111.397	0.000	0.000	0.000
2	M	17:00		114.560	0.000	114.560	0.0	114.560	0.0	114.560	0.000	0.000	0.000
3	TU	15:00		128.332	0.000	128.332	0.0	128.332	0.0	128.332	0.000	0.000	0.000
4	W	17:00		118.934	0.000	118.934	0.0	118.934	0.0	118.934	0.000	0.000	0.000
5	TH	17:00		111.732	0.000	111.732	0.0	111.732	0.0	111.732	0.000	0.000	0.000
6	F	16:00		108.094	0.000	108.094	0.0	108.094	0.0	108.094	0.000	0.000	0.000
7	S	16:00		108.577	0.000	108.577	0.0	108.577	0.0	108.577	0.000	0.000	0.000
8	SU	17:00		120.418	0.000	120.418	0.0	120.418	0.0	120.418	0.000	0.000	0.000
9	M	16:00		116.071	0.000	116.071	0.0	116.071	0.0	116.071	0.000	0.000	0.000
10	TU	17:00		121.433	0.000	121.433	0.0	121.433	0.0	121.433	0.000	0.000	0.000
11	W	15:00	*	**131.298**	**0.000**	**131.298**	**0.0**	**131.298**	**0.0**	**131.298**	**131.298**	**0.000**	**0.000**
12	TH	17:00		132.350	0.000	132.350	0.0	132.350	0.0	132.350	0.000	0.000	0.000
13	F	12:00		128.435	0.000	128.435	0.0	128.435	0.0	128.435	0.000	0.000	0.000
14	S	16:00		101.453	0.000	101.453	0.0	101.453	0.0	101.453	0.000	0.000	0.000
15	SU	15:00		99.392	0.000	99.392	0.0	99.392	0.0	99.392	0.000	0.000	0.000
16	M	15:00		85.071	0.000	85.071	0.0	85.071	0.0	85.071	0.000	0.000	0.000
17	TU	15:00		96.978	0.000	96.978	0.0	96.978	0.0	96.978	0.000	0.000	0.000
18	W	15:00		98.782	0.000	98.782	0.0	98.782	0.0	98.782	0.000	0.000	0.000
19	TH	17:00		99.973	0.000	99.973	0.0	99.973	0.0	99.973	0.000	0.000	0.000
20	F	17:00		105.573	0.000	105.573	0.0	105.573	0.0	105.573	0.000	0.000	0.000
21	S	17:00		106.489	0.000	106.489	0.0	106.489	0.0	106.489	0.000	0.000	0.000
22	SU	17:00		115.106	0.000	115.106	0.0	115.106	0.0	115.106	0.000	0.000	0.000
23	M	16:00		111.806	0.000	111.806	0.0	111.806	0.0	111.806	0.000	0.000	0.000
24	TU	16:00		109.790	0.000	109.790	0.0	109.790	0.0	109.790	0.000	0.000	0.000
25	W	17:00		119.536	0.000	119.536	0.0	119.536	0.0	119.536	0.000	0.000	0.000
26	TH	17:00		122.693	0.000	122.693	0.0	122.693	0.0	122.693	0.000	0.000	0.000
27	F	17:00		129.429	0.000	129.429	0.0	129.429	0.0	129.429	0.000	0.000	0.000
28	S	17:00		124.329	0.000	124.329	0.0	124.329	0.0	124.329	0.000	0.000	0.000
29	SU	16:00		130.898	0.000	130.898	0.0	130.898	0.0	130.898	0.000	0.000	0.000
30	M	17:00		132.975	0.000	132.975	0.0	132.975	0.0	132.975	0.000	0.000	0.000
31	TU	16:00		132.945	0.000	132.945	0.0	132.945	0.0	132.945	0.000	0.000	0.000
MAXIMUM				132.975	0.000	132.975	0.0	132.975	0.0	132.975	131.298	0.000	0.000

SSVEC ALLOCATED CAPACITY (MW)		**142.300**	**MW**
SSVEC Demand at AEPCO Billing Peak (MW)		**131.298**	**MW**
Schedule A Demand Overrun = highest over AC at Peak (MW & %)	**0.000**	**0.000%**	**(1)**
SSVEC AEPCO Profile Capacity = Min O&M Capacity with MR sched (MW)		**120.300**	
Schedule B Capacity Available (AC less Profile Capacity) (MW)		**22.000**	

NOTE: (1) MW of Schedule A Demand Overrun is billed through 12/31/2005 as Supplemental Capacity per the Supplemental C&E Agreement .

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
SCHEDULE B DEMAND OVERRUN SUMMARY

SAMPLE INVOICE

AUGUST, 2004

SULPHUR SPRINGS PEAK

DAY	DAY OF WEEK	TIME	A SSVEC SCHED AT SSVEC NON COINCIDENTAL PEAK MW	B SSVEC AEPCO SALES MW	C A + B TOTAL MW	D RESOURCE SCHEDULE for SSVEC WHEELING (MEMBER JMP & CSP JMP) MW	E C - D LOAD for AEPCO & MEMBER RESOURCES MW	F MEMBER RESOURCE SCHEDULE for SSVEC INTERNAL LOADS MW	G E - F AEPCO RESOURCE USED MW	H G - ALLOC CAP AEPCO RESOURCE above AC (Sched B) MW
1	SU	12:30	119.662	0.000	119.662	0.000	119.662	0.000	119.662	0.000
2	M	16:30	115.227	0.000	115.227	0.000	115.227	0.000	115.227	0.000
3	TU	14:00	128.507	0.000	128.507	0.000	128.507	0.000	128.507	0.000
4	W	15:00	123.229	0.000	123.229	0.000	123.229	0.000	123.229	0.000
5	TH	16:00	115.597	0.000	115.597	0.000	115.597	0.000	115.597	0.000
6	F	13:00	113.639	0.000	113.639	0.000	113.639	0.000	113.639	0.000
7	S	13:00	122.777	0.000	122.777	0.000	122.777	0.000	122.777	0.000
8	SU	14:30	131.263	0.000	131.263	0.000	131.263	0.000	131.263	0.000
9	M	13:30	137.383	0.000	137.383	0.000	137.383	0.000	137.383	0.000
10	TU	13:00	132.298	0.000	132.298	0.000	132.298	0.000	132.298	0.000
11	**W**	**12:30**	**139.160**	**0.000**	**139.160**	**0.000**	**139.160**	**0.000**	**139.160**	**0.000**
12	TH	16:00	137.695	0.000	137.695	0.000	137.695	0.000	137.695	0.000
13	F	12:00	128.435	0.000	128.435	0.000	128.435	0.000	128.435	0.000
14	S	20:00	101.994	0.000	101.994	0.000	101.994	0.000	101.994	0.000
15	SU	14:30	101.161	0.000	101.161	0.000	101.161	0.000	101.161	0.000
16	M	10:30	95.083	0.000	95.083	0.000	95.083	0.000	95.083	0.000
17	TU	13:30	99.801	0.000	99.801	0.000	99.801	0.000	99.801	0.000
18	W	13:00	103.355	0.000	103.355	0.000	103.355	0.000	103.355	0.000
19	TH	17:00	99.973	0.000	99.973	0.000	99.973	0.000	99.973	0.000
20	F	16:00	105.865	0.000	105.865	0.000	105.865	0.000	105.865	0.000
21	S	16:00	107.090	0.000	107.090	0.000	107.090	0.000	107.090	0.000
22	SU	16:30	115.368	0.000	115.368	0.000	115.368	0.000	115.368	0.000
23	M	14:00	115.713	0.000	115.713	0.000	115.713	0.000	115.713	0.000
24	TU	16:30	109.843	0.000	109.843	0.000	109.843	0.000	109.843	0.000
25	W	17:00	119.536	0.000	119.536	0.000	119.536	0.000	119.536	0.000
26	TH	16:30	124.670	0.000	124.670	0.000	124.670	0.000	124.670	0.000
27	F	16:00	129.673	0.000	129.673	0.000	129.673	0.000	129.673	0.000
28	S	14:00	129.844	0.000	129.844	0.000	129.844	0.000	129.844	0.000
29	SU	15:00	132.486	0.000	132.486	0.000	132.486	0.000	132.486	0.000
30	M	16:00	135.617	0.000	135.617	0.000	135.617	0.000	135.617	0.000
31	TU	15:30	133.632	0.000	133.632	0.000	133.632	0.000	133.632	0.000
MAXIMUM			139.160	0.000	139.160	0.000	139.160	0.000	139.160	**0.000**

SSVEC Allocated Capacity (MW) **142.300 MW**
Schedule B Demand Overrun (MW) **0.000 MW**
SCHEDULE B DEMAND OVERRUN % **0.00%**

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
SCHEDULE B
OVERRUN ENERGY ADJUSTMENT SUMMARY
SAMPLE INVOICE
AUGUST, 2004

DAY	A SSVEC LOAD MWh	B ENERGY RECEIVED for SSVEC WHEELING (MEMBER JMP & CSP JMP) MWH	C ENERGY from MEMBER RESOURCE for SSVEC INTERNAL LOAD MWH	D ENERGY SCHEDULE for SSVEC AEPCO SALE MWH	A-B-C+D TOTAL ENERGY from AEPCO RESOURCES SUPPLIED to SSVEC MWH	SSVEC SCHEDULE SCHED A ENERGY MWh	SSVEC SCHEDULE BOUNDED (SHIFTED) SCHED A ENERGY MWh	SSVEC TOTAL SCHEDULE SCHED A ENERGY MWh	SSVEC SCHEDULE SCHED B ENERGY MWh	SCHED B RATE GREATER of SCHED A RATE ($20.71) or HIGHEST RESOURCE COST $/MWh	SCHED B ENERGY CHARGE $
1	2,144.448	0.000	0.000	0.000	2,144.448	2,051.462	0.000	2,051.462	92.986	$56.905	$5,291.41
2	2,161.562	0.000	0.000	0.000	2,161.562	2,110.222	0.000	2,110.222	51.340	$66.317	$3,404.71
3	2,301.499	0.000	0.000	0.000	2,301.499	2,124.547	0.000	2,124.547	176.952	$70.638	$12,499.50
4	2,303.866	0.000	0.000	0.000	2,303.866	2,150.546	0.000	2,150.546	153.320	$56.703	$8,693.67
5	2,156.430	0.000	0.000	0.000	2,156.430	2,135.911	0.000	2,135.911	20.519	$63.000	$1,292.70
6	2,116.122	0.000	0.000	0.000	2,116.122	2,084.509	0.000	2,084.509	31.613	$52.787	$1,668.76
7	2,177.249	0.000	0.000	0.000	2,177.249	2,106.533	0.000	2,106.533	70.716	$53.982	$3,817.36
8	2,302.030	0.000	0.000	0.000	2,302.030	2,048.411	0.000	2,048.411	253.619	$35.119	$8,906.86
9	2,402.100	0.000	0.000	0.000	2,402.100	2,173.219	0.000	2,173.219	228.881	$57.252	$13,103.82
10	2,455.454	0.000	0.000	0.000	2,455.454	2,158.847	0.000	2,158.847	296.607	$52.366	$15,531.99
11	2,488.111	0.000	0.000	0.000	2,488.111	2,186.151	0.000	2,186.151	301.960	$60.709	$18,331.78
12	2,545.506	0.000	0.000	0.000	2,545.506	2,196.055	0.000	2,196.055	349.451	$56.526	$19,753.16
13	2,266.598	0.000	0.000	0.000	2,266.598	2,147.843	0.000	2,147.843	118.755	$56.344	$6,691.17
14	2,017.967	0.000	0.000	0.000	2,017.967	2,016.808	0.000	2,016.808	1.159	$38.000	$44.04
15	1,919.776	0.000	0.000	0.000	1,919.776	1,919.776	0.000	1,919.776	0.000	$0.000	$0.00
16	1,861.307	0.000	0.000	0.000	1,861.307	1,861.307	0.000	1,861.307	0.000	$0.000	$0.00
17	1,906.429	0.000	0.000	0.000	1,906.429	1,906.429	0.000	1,906.429	0.000	$0.000	$0.00
18	1,904.162	0.000	0.000	0.000	1,904.162	1,904.162	0.000	1,904.162	0.000	$0.000	$0.00
19	1,849.692	0.000	0.000	0.000	1,849.692	1,849.692	0.000	1,849.692	0.000	$0.000	$0.00
20	1,904.868	0.000	0.000	0.000	1,904.868	1,904.868	0.000	1,904.868	0.000	$0.000	$0.00
21	1,896.300	0.000	0.000	0.000	1,896.300	1,896.300	0.000	1,896.300	0.000	$47.696	$0.00
22	2,020.932	0.000	0.000	0.000	2,020.932	1,947.128	0.000	1,947.128	73.804	$47.696	$3,520.14
23	2,160.086	0.000	0.000	0.000	2,160.086	2,096.454	0.000	2,096.454	63.632	$42.512	$2,705.13
24	2,118.758	0.000	0.000	0.000	2,118.758	2,109.506	0.000	2,109.506	9.252	$33.704	$311.83
25	2,221.278	0.000	0.000	0.000	2,221.278	2,135.977	0.000	2,135.977	85.301	$51.018	$4,351.90
26	2,290.039	0.000	0.000	0.000	2,290.039	2,137.590	0.000	2,137.590	152.449	$49.154	$7,493.40
27	2,368.793	0.000	0.000	0.000	2,368.793	2,153.528	0.000	2,153.528	215.265	$54.951	$11,828.98
28	2,377.108	0.000	0.000	0.000	2,377.108	2,155.625	0.000	2,155.625	221.483	$55.559	$12,305.48
29	2,355.490	0.000	0.000	0.000	2,355.490	2,069.518	0.000	2,069.518	285.972	$47.014	$13,444.59
30	2,456.057	0.000	0.000	0.000	2,456.057	2,154.860	0.000	2,154.860	301.197	$50.848	$15,315.30
31	2,421.631	0.000	0.000	0.000	2,421.631	2,167.666	0.000	2,167.666	253.965	$50.895	$12,925.54
TOTAL	67,871.648	0.000	0.000	0.000	67,871.648	64,061.450	0.000	64,061.450	3,810.198	$53.339	$203,233.22

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
SCHEDULE B
MINIMUM ENERGY ADJUSTMENT SUMMARY
SAMPLE INVOICE
AUGUST, 2004

DAY	SSVEC LOAD MWh	ENERGY RECEIVED for SSVEC WHEELING (MEMBER JMP & CSP JMP) MWH	ENERGY from MEMBER RESOURCE for SSVEC INTERNAL LOAD MWH	ENERGY SCHEDULE for SSVEC AEPCO SALE MWH	SSVEC TOTAL SCHEDULE MWh	ENERGY from ALLOC CAPACITY SUPPLIED to SSVEC MWH	SSVEC SHARE of MINIMUM BASE CAPACITY MWh	ENERGY BELOW SSVEC SHARE of AEPCO MINIMUM BASE CAPACITY MWh	SCHED B MINIMUM ENERGY RATE $/MWh	SCHED B MINIMUM ENERGY CHARGE $
1	2,144.448	0.000	0.000	0.000	2,144.448	2,144.448	1,200.000	0	$0.000	$0.00
2	2,161.562	0.000	0.000	0.000	2,161.562	2,161.562	1,292.800	0	$0.000	$0.00
3	2,301.499	0.000	0.000	0.000	2,301.499	2,301.499	1,292.800	0	$0.000	$0.00
4	2,303.866	0.000	0.000	0.000	2,303.866	2,303.866	1,292.800	0	$0.000	$0.00
5	2,156.430	0.000	0.000	0.000	2,156.430	2,156.430	1,292.800	0	$0.000	$0.00
6	2,116.122	0.000	0.000	0.000	2,116.122	2,116.122	1,292.800	0	$0.000	$0.00
7	2,177.249	0.000	0.000	0.000	2,177.249	2,177.249	1,292.800	0	$0.000	$0.00
8	2,302.030	0.000	0.000	0.000	2,302.030	2,302.030	1,200.000	0	$0.000	$0.00
9	2,402.100	0.000	0.000	0.000	2,402.100	2,402.100	1,292.800	0	$0.000	$0.00
10	2,455.454	0.000	0.000	0.000	2,455.454	2,455.454	1,292.800	0	$0.000	$0.00
11	2,488.111	0.000	0.000	0.000	2,488.111	2,488.111	1,292.800	0	$0.000	$0.00
12	2,545.506	0.000	0.000	0.000	2,545.506	2,545.506	1,292.800	0	$0.000	$0.00
13	2,266.598	0.000	0.000	0.000	2,266.598	2,266.598	1,292.800	0	$0.000	$0.00
14	2,017.967	0.000	0.000	0.000	2,017.967	2,017.967	1,292.800	0	$0.000	$0.00
15	1,919.776	0.000	0.000	0.000	1,919.776	1,919.776	1,200.000	0	$0.000	$0.00
16	1,861.307	0.000	0.000	0.000	1,861.307	1,861.307	1,292.800	0	$0.000	$0.00
17	1,906.429	0.000	0.000	0.000	1,906.429	1,906.429	1,292.800	0	$0.000	$0.00
18	1,904.162	0.000	0.000	0.000	1,904.162	1,904.162	1,292.800	0	$0.000	$0.00
19	1,849.692	0.000	0.000	0.000	1,849.692	1,849.692	1,292.800	0	$0.000	$0.00
20	1,904.868	0.000	0.000	0.000	1,904.868	1,904.868	1,292.800	0	$0.000	$0.00
21	1,896.300	0.000	0.000	0.000	1,896.300	1,896.300	1,292.800	0	$0.000	$0.00
22	2,020.932	0.000	0.000	0.000	2,020.932	2,020.932	1,200.000	0	$0.000	$0.00
23	2,160.086	0.000	0.000	0.000	2,160.086	2,160.086	1,292.800	0	$0.000	$0.00
24	2,118.758	0.000	0.000	0.000	2,118.758	2,118.758	1,292.800	0	$0.000	$0.00
25	2,221.278	0.000	0.000	0.000	2,221.278	2,221.278	1,292.800	0	$0.000	$0.00
26	2,290.039	0.000	0.000	0.000	2,290.039	2,290.039	1,292.800	0	$0.000	$0.00
27	2,368.793	0.000	0.000	0.000	2,368.793	2,368.793	1,292.800	0	$0.000	$0.00
28	2,377.108	0.000	0.000	0.000	2,377.108	2,377.108	1,292.800	0	$0.000	$0.00
29	2,355.490	0.000	0.000	0.000	2,355.490	2,355.490	1,200.000	0	$0.000	$0.00
30	2,456.057	0.000	0.000	0.000	2,456.057	2,456.057	1,292.800	0	$0.000	$0.00
31	2,421.631	0.000	0.000	0.000	2,421.631	2,421.631	1,292.800	0	$0.000	$0.00
TOTAL	67,871.648	0.000	0.000	0.000	67,871.648	67,871.648	39,612.800	0	$0.000	$0.00

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
SUMMARY OF SUPPLEMENTAL ENERGY CALCULATION (1)
AUGUST, 2004

SAMPLE INVOICE

ALLOCATED CAPACITY **142.300**

DAY	MEC LOAD MWH	MEC ALLOCATED RESOURCES MWH	PARTIAL	SUPPLEMENTAL ENERGY MWH
1	2,144.448	3,276.000	2,144.448	0.000
2	2,161.562	3,368.800	2,161.562	0.000
3	2,301.499	3,368.800	2,301.499	0.000
4	2,303.866	3,368.800	2,303.866	0.000
5	2,156.430	3,368.800	2,156.430	0.000
6	2,116.122	3,368.800	2,116.122	0.000
7	2,177.249	3,368.800	2,177.249	0.000
8	2,302.030	3,276.000	2,302.030	0.000
9	2,402.100	3,368.800	2,402.100	0.000
10	2,455.454	3,368.800	2,455.454	0.000
11	2,488.111	3,368.800	2,488.111	0.000
12	2,545.506	3,368.800	2,545.506	0.000
13	2,266.598	3,368.800	2,266.598	0.000
14	2,017.967	3,368.800	2,017.967	0.000
15	1,919.776	3,276.000	1,919.776	0.000
16	1,861.307	3,368.800	1,861.307	0.000
17	1,906.429	3,368.800	1,906.429	0.000
18	1,904.162	3,368.800	1,904.162	0.000
19	1,849.692	3,368.800	1,849.692	0.000
20	1,904.868	3,368.800	1,904.868	0.000
21	1,896.300	3,368.800	1,896.300	0.000
22	2,020.932	3,276.000	2,020.932	0.000
23	2,160.086	3,368.800	2,160.086	0.000
24	2,118.758	3,368.800	2,118.758	0.000
25	2,221.278	3,368.800	2,221.278	0.000
26	2,290.039	3,368.800	2,290.039	0.000
27	2,368.793	3,368.800	2,368.793	0.000
28	2,377.108	3,368.800	2,377.108	0.000
29	2,355.490	3,276.000	2,355.490	0.000
30	2,456.057	3,368.800	2,456.057	0.000
31	2,421.631	3,368.800	2,421.631	0.000
TOTAL	67,871.648	103,968.800	67,871.648	0.000

METER READ **67,871.156 MWH**
LESS:PARTIAL **67,871.648 MWH**

SUPPL FOR BILLING **(0.492) MWH**

NOTE: (1) Supplemental Energy applies through 12/31/05 under the Supplemental C&E Agr.

Exhibit A-5 to Rate Schedule A
Allocated Capacity Percentages (ACP)
and Allocated Capacity (AC)

ACP and AC DETERMINATION

An Allocated Capacity Percentage (ACP) was developed as of the Effective Date for each Class A Member based on load forecasts from the 1996 Power Requirements Study (1996 PRS). The ACP is used to calculate the Allocated Capacity (AC) for each Partial Requirements Member. AEPCO, all AEPCO Class A Members, and RUS have approved the use of the 1996 PRS for planning purposes. The specific use of the 1996 PRS and forecast year 2000 were chosen as the basis for calculating the ACP set forth herein because: (i) the annual coincident peak of AEPCO best matched the Existing Resources in forecast year 2000, and (ii) after forecast year 2000, AEPCO was projected to need additional Resources. The calculation used in determining the ACP is summarized in Appendix A to this Exhibit A-5. The ACP calculation utilizes the forecasted year 2000 monthly coincident peaks of the Class A Members, which are obtained by multiplying: (a) each Member's forecasted monthly non-coincident peak as identified in the 1996 PRS, by (b) a historical three-year average coincident factor. The resulting twelve monthly coincident peaks were summed both for each Class A Member and for all Class A Members. The ACP for each Class A Member represents the percentage quotient of (a) the sum of the monthly coincident peaks for that Class A Member divided by (b) the sum of the monthly coincident peaks for all Class A Members.

The ACP of a Partial Requirements Member is used to apportion AEPCO's Resources (after reductions for existing Power Sales Resources, associated losses and reserves) to determine the AC for that Partial Requirements Member. The AC for a Partial Requirements Member is calculated by: (1) determining the capacity (in MW) of the Existing Resources; (2) subtracting the Power Sales Resources as of the Closing Date, or as subsequently approved by the Partial Requirements Member, to determine adjusted Existing Resource capacity; (3) reducing the adjusted Existing Resource capacity for losses and reserves attributable to Power Sales, to determine net AEPCO Existing Resource capacity attributable to the Class A Members; (4) multiplying such net AEPCO Existing Resource capacity attributable to the Class A Members by the ACP of that Partial Requirements Member as set forth in Section A of Appendix A hereto; (5) adding to the result from (4) above the portion of the Member's AC attributable to the PGR PPA, which shall be the product of: (i) the ACP of such Member as set forth in Section B of Appendix A hereto, multiplied by (ii) the capacity in MW of the PGR PPA as set forth in Appendix B hereto; and (6) reducing the result from (5) above for reserves and losses for that Partial Requirements Member.

The calculation of the AC of SSVEC through 2035 is depicted within Appendix B to this Exhibit A-5. As later power requirements studies become available, the AC of SSVEC for any later termination of the Agreement shall be calculated as set forth above, based on the ACP of SSVEC.

Appendix A to Exhibit A-5
Schedule of Allocated Capacity Percentages

A. The schedule and calculation of the Allocated Capacity Percentages (ACP) for AEPCO Resources existing as of the Effective Date (consisting of Existing Resources as set forth in Appendix B to Exhibit A-5) is shown below:

	Allocated Capacity Percentage							
	1996 PRS Coincident Peak Demand Forecast – MW							
Col.		1	2	3	4	5	6	7
Ln.	Year 2000	Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
1	January	6.0	3.2	15.9	70.5	80.8	57.1	233.5
2	February	5.6	2.9	15.1	62.7	76.9	48.7	211.9
3	March	5.8	2.9	15.7	60.4	70.9	44.2	199.9
4	April	4.8	2.8	15.8	64.4	66.8	44.0	198.7
5	May	5.2	3.1	19.5	80.2	77.3	44.4	229.7
6	June	6.6	3.8	25.0	105.4	87.3	49.3	277.4
7	July	6.7	4.3	26.3	127.0	92.6	67.4	324.4
8	August	8.0	4.4	25.0	130.5	88.7	69.0	325.6
9	September	7.7	3.8	22.3	120.8	85.1	60.9	300.7
10	October	6.5	3.2	16.8	106.5	78.0	52.7	263.7
11	November	5.7	3.0	16.1	79.5	77.0	49.1	230.4
12	December	5.8	3.4	16.2	76.4	79.2	51.4	232.4
13	Annual Total	74.6	40.8	229.8	1084.3	960.6	638.1	3028.2
14	Allocated Capacity %	2.5%	1.3%	7.6%	35.8%	31.7%	21.1%	100.0%

Notes: Line 13 = sum of lines 1 through 12
Line 14, Col. 1 = Line 13, Col. 1 / Line 13, Col. 7
Line 14, Col. 2 = Line 13, Col. 2 / Line 13, Col. 7
Line 14, Col. 3 = Line 13, Col. 3 / Line 13, Col. 7
Line 14, Col. 4 = Line 13, Col. 4 / Line 13, Col. 7
Line 14, Col. 5 = Line 13, Col. 5 / Line 13, Col. 7
Line 14, Col. 6 = Line 13, Col. 6 / Line 13, Col. 7

B. The Allocated Capacity Percentages (ACP's) for the PGR PPA is 0% for MEC. For the remaining Class A Members, the resulting ACP's for the PGR PPA are as follows:

	Anza	Duncan	Graham	Sulphur	Trico	Total
Allocated Capacity %	3.9%	2.0%	11.8%	49.4%	32.9%	100%

Appendix B to Exhibit A-5

Monthly Allocated Capacity for 2001

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	35.0	35.0	5.0	0.0	0.0	0.0
Public Service of New Mexico		66.0	66.0	66.0	66.0	66.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
SLCA - IP	** Note 1 **	1.7	1.7	1.5	7.4	7.5	7.8	8.9	8.3	7.3	1.5	1.5	1.7
Parker-Davis	** Note 2 **	18.4	18.4	23.8	23.8	23.8	23.8	23.8	23.8	23.8	18.4	18.4	18.4
Existing Resources		**603.1**	**603.1**	**608.3**	**614.2**	**614.3**	**638.6**	**674.7**	**674.1**	**643.1**	**626.9**	**626.9**	**627.1**
Electrical District 2 Firm		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Mesa 15 Firm		15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Mesa 17.5 Contingent		17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
Cyprus Firm		5.0	5.0	5.0	9.1	9.2	10.2	11.2	11.3	10.9	10.8	10.3	10.1
Cyprus Contingent		1.6	1.8	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total Other Firm Loads		228.0	228.0	228.0	232.1	232.2	233.2	234.2	234.3	233.9	233.8	233.3	233.1
Total Other Contingent Loads		19.1	19.3	19.4	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
Power Sales Resources		**247.1**	**247.3**	**247.4**	**249.6**	**249.7**	**250.7**	**251.7**	**251.8**	**251.4**	**251.3**	**250.8**	**250.6**
Adjusted Existing Resource Capacity		**356.0**	**355.8**	**360.9**	**364.6**	**364.6**	**387.9**	**423.0**	**422.3**	**391.7**	**375.6**	**376.1**	**376.5**
Power Sales Losses 2.97%		6.8	6.8	6.8	6.9	6.9	6.9	7.0	7.0	6.9	6.9	6.9	6.9
% Reserves Required (SRSG Methodology)		16.6%	17.0%	17.1%	18.0%	16.2%	15.0%	13.4%	12.7%	13.4%	14.8%	15.8%	15.0%
Power Sales Reserves @ > of 12% or SRSG		37.8	38.7	39.0	41.9	37.5	35.0	31.5	29.7	31.3	34.5	36.9	34.9
Net Existing Resource Capacity		**311.5**	**310.3**	**315.2**	**315.9**	**320.2**	**346.0**	**384.5**	**385.7**	**353.4**	**334.1**	**332.3**	**334.7**
Additional Resources - PGR PPA		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		98.7	98.4	99.9	100.1	101.5	109.7	121.9	122.3	112.0	105.9	105.3	106.1
Sulphur Reserves @ > of 12% or SRSG		13.7	13.9	14.2	14.9	13.8	14.0	14.1	13.4	12.9	13.3	14.0	13.5
Sulphur Losses @ 2.97%		2.5	2.4	2.5	2.5	2.5	2.8	3.1	3.1	2.9	2.7	2.6	2.7
Partial Requirements Allocated Capacity (Sulphur)		**82.6**	**82.0**	**83.2**	**82.7**	**85.2**	**93.0**	**104.7**	**105.7**	**96.3**	**90.0**	**88.7**	**89.9**
Sulphur Springs Valley Table B-1.2 Peaks		81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Sulphur Surplus (Deficiency)		**1.0**	**7.4**	**13.8**	**12.2**	**8.6**	**4.6**	**13.3**	**16.4**	**15.7**	**13.2**	**19.1**	**6.3**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2004

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
SLCA - IP	** Note 1 **	1.7	1.7	1.5	7.4	7.5	7.8	8.9	8.3	7.3	1.4	1.4	1.6
Parker-Davis	** Note 2 **	18.4	18.4	23.8	23.8	23.8	23.8	23.8	23.8	23.8	18.4	18.4	18.4
Existing Resources		590.1	590.1	595.3	601.2	601.3	601.6	602.7	602.1	601.1	589.8	589.8	590.0
Electrical District 2 Firm		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Mesa 15 Firm		15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0
Adjusted Existing Resource Capacity		467.1	467.1	472.3	478.2	478.3	478.6	479.7	479.1	478.1	466.8	466.8	467.0
Power Sales Losses 2.97%		3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
% Reserves Required (SRSG Methodology)		14.4%	15.3%	18.0%	20.2%	18.1%	15.8%	14.5%	13.2%	13.4%	15.6%	17.8%	15.5%
Power Sales Reserves @ > of 12% or SRSG		17.7	18.9	22.1	24.9	22.2	19.5	17.8	16.2	16.5	19.2	21.9	19.1
Net Existing Resource Capacity		445.8	444.6	446.6	449.7	452.4	455.5	458.2	459.2	457.9	443.9	441.3	444.3
Additional Resources - PGR PPA		0.0	0.0	0.0	0.0	40.0	40.0	40.0	40.0	40.0	0.0	0.0	0.0
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		141.3	140.9	141.6	142.6	163.2	164.1	165.0	165.3	164.9	140.7	139.9	140.8
Sulphur Reserves @ > of 12% or SRSG		17.3	18.3	21.1	23.4	24.3	21.9	20.3	18.8	19.0	18.6	20.6	18.4
Sulphur Losses @ 2.97%		3.6	3.5	3.5	3.4	4.0	4.1	4.2	4.2	4.2	3.5	3.4	3.5
Partial Requirements Allocated Capacity (Sulphur)		120.4	119.1	117.0	115.7	134.8	138.2	140.5	142.3	141.7	118.6	115.8	118.9
Sulphur 2004 Final TRS NC Peak		102.3	101.4	94.9	102.5	124.6	140.3	142.8	139.5	124.5	103.6	99.3	105.1
Sulphur Surplus (Deficiency)		18.1	17.7	22.1	13.3	10.2	(2.1)	(2.3)	2.8	17.1	15.0	16.5	13.8

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2005

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	18.4	18.4	23.8	23.8	23.8	23.8	23.8	23.8	23.8	18.4	18.4	18.4
Existing Resources		**590.0**	**590.0**	**595.2**	**600.7**	**600.8**	**601.1**	**602.0**	**601.6**	**600.6**	**589.8**	**589.8**	**590.0**
Electrical District 2 Firm		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Mesa 15 Firm		15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**
Adjusted Existing Resource Capacity		**467.0**	**467.0**	**472.2**	**477.7**	**477.8**	**478.1**	**479.0**	**478.6**	**477.6**	**466.8**	**466.8**	**467.0**
Power Sales Losses 2.97%		3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
% Reserves Required (SRSG Methodology)		14.3%	15.2%	17.8%	20.0%	18.2%	16.0%	14.6%	13.3%	13.6%	15.9%	17.9%	15.6%
Power Sales Reserves @ > of 12% or SRSG		17.5	18.7	22.0	24.6	22.4	19.6	17.9	16.4	16.7	19.5	22.0	19.2
Net Existing Resource Capacity		**445.8**	**444.6**	**446.6**	**449.4**	**451.7**	**454.8**	**457.5**	**458.5**	**457.2**	**443.6**	**441.2**	**444.1**
Additional Resources - PGR PPA		**0.0**	**0.0**	**0.0**	**0.0**	**60.0**	**60.0**	**60.0**	**60.0**	**60.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		141.3	140.9	141.6	142.5	172.8	173.8	174.6	175.0	174.6	140.6	139.9	140.8
Sulphur Reserves @ > of 12% or SRSG		17.2	18.2	20.9	23.2	26.0	23.3	21.6	20.0	20.3	18.8	20.7	18.6
Sulphur Losses @ 2.97%		3.6	3.5	3.5	3.4	4.2	4.3	4.4	4.5	4.4	3.5	3.4	3.5
Partial Requirements Allocated Capacity (Sulphur)		**120.5**	**119.2**	**117.2**	**115.8**	**142.6**	**146.1**	**148.6**	**150.5**	**149.8**	**118.3**	**115.7**	**118.7**
Sulphur 2004 Final TRS NC Peak		106.2	105.5	98.6	106.4	129.3	145.5	147.7	144.3	128.9	107.3	102.8	108.5
Sulphur Surplus (Deficiency)		**14.3**	**13.7**	**18.6**	**9.4**	**13.3**	**0.6**	**0.9**	**6.2**	**20.9**	**11.1**	**12.9**	**10.2**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2006

All Values in MW Unless Indicated	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
SLCA - IP ** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis ** Note 2 **	18.4	18.4	23.8	23.8	23.8	23.8	23.8	23.8	23.8	18.4	18.4	18.4
Existing Resources	**590.0**	**590.0**	**595.2**	**600.7**	**600.8**	**601.1**	**602.0**	**601.6**	**600.6**	**589.8**	**589.8**	**590.0**
Electrical District 2 Firm	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Mesa 15 Firm	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Mesa 17.5 Contingent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0
Total Other Contingent Loads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**
Adjusted Existing Resource Capacity	**467.0**	**467.0**	**472.2**	**477.7**	**477.8**	**478.1**	**479.0**	**478.6**	**477.6**	**466.8**	**466.8**	**467.0**
Power Sales Losses 2.97%	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
% Reserves Required (SRSG Methodology)	14.4%	15.3%	17.9%	20.1%	18.4%	16.1%	14.6%	13.4%	13.7%	16.1%	18.0%	15.9%
Power Sales Reserves @ > of 12% or SRSG	17.7	18.8	22.0	24.7	22.6	19.8	18.0	16.5	16.9	19.9	22.1	19.5
Net Existing Resource Capacity	**445.7**	**444.5**	**446.6**	**449.4**	**451.5**	**454.6**	**457.4**	**458.5**	**457.0**	**443.3**	**441.1**	**443.8**
Additional Resources - PGR PPA	**0.0**	**0.0**	**0.0**	**0.0**	**75.0**	**75.0**	**75.0**	**75.0**	**75.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional	141.3	140.9	141.6	142.5	180.2	181.2	182.0	182.4	181.9	140.5	139.8	140.7
Sulphur Reserves @ > of 12% or SRSG	17.3	18.2	21.0	23.2	27.3	24.5	22.6	21.0	21.4	19.0	20.8	18.8
Sulphur Losses @ 2.97%	3.6	3.5	3.5	3.4	4.4	4.5	4.6	4.7	4.6	3.5	3.4	3.5
Partial Requirements Allocated Capacity (Sulphur)	**120.4**	**119.1**	**117.1**	**115.8**	**148.4**	**152.2**	**154.8**	**156.7**	**155.9**	**118.0**	**115.6**	**118.4**
Sulphur 2004 Final TRS NC Peak	109.8	109.2	102.0	110.2	133.9	150.5	152.4	148.9	133.2	110.9	106.2	112.0
Sulphur Surplus (Deficiency)	**10.7**	**9.9**	**15.1**	**5.6**	**14.6**	**1.7**	**2.4**	**7.8**	**22.7**	**7.1**	**9.4**	**6.4**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2007

All Values in MW Unless Indicated	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
SLCA - IP ** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis ** Note 2 **	18.4	18.4	23.8	23.8	23.8	23.8	23.8	23.8	23.8	18.4	18.4	18.4
Existing Resources	**590.0**	**590.0**	**595.2**	**600.7**	**600.8**	**601.1**	**602.0**	**601.6**	**600.6**	**589.8**	**589.8**	**590.0**
Electrical District 2 Firm	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Mesa 15 Firm	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Mesa 17.5 Contingent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0
Total Other Contingent Loads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**
Adjusted Existing Resource Capacity	**467.0**	**467.0**	**472.2**	**477.7**	**477.8**	**478.1**	**479.0**	**478.6**	**477.6**	**466.8**	**466.8**	**467.0**
Power Sales Losses 2.97%	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
% Reserves Required (SRSG Methodology)	14.6%	15.6%	17.9%	20.0%	18.5%	16.2%	14.7%	13.5%	13.9%	16.4%	18.2%	16.1%
Power Sales Reserves @ > of 12% or SRSG	17.9	19.1	22.1	24.6	22.8	19.9	18.1	16.6	17.0	20.1	22.4	19.8
Net Existing Resource Capacity	**445.4**	**444.1**	**446.5**	**449.5**	**451.4**	**454.5**	**457.3**	**458.3**	**456.9**	**443.0**	**440.8**	**443.5**
Additional Resources - PGR PPA	**0.0**	**0.0**	**0.0**	**0.0**	**85.0**	**85.0**	**85.0**	**85.0**	**85.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional	141.2	140.8	141.5	142.5	185.1	186.1	186.9	187.3	186.8	140.4	139.7	140.6
Sulphur Reserves @ > of 12% or SRSG	17.5	18.5	21.0	23.2	28.2	25.3	23.4	21.7	22.2	19.3	21.0	19.0
Sulphur Losses @ 2.97%	3.6	3.5	3.5	3.4	4.5	4.6	4.7	4.8	4.7	3.5	3.4	3.5
Partial Requirements Allocated Capacity (Sulphur)	**120.1**	**118.8**	**117.1**	**115.9**	**152.3**	**156.1**	**158.8**	**160.8**	**159.9**	**117.7**	**115.3**	**118.1**
Sulphur 2004 Final TRS NC Peak	113.2	112.9	105.3	113.5	137.8	154.8	156.6	153.0	137.1	114.4	109.6	115.4
Sulphur Surplus (Deficiency)	**6.9**	**5.9**	**11.8**	**2.4**	**14.6**	**1.4**	**2.3**	**7.8**	**22.8**	**3.3**	**5.6**	**2.6**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2008

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	18.4	18.4	23.8	23.8	23.8	23.8	23.8	23.8	23.8	17.3	17.3	17.3
Existing Resources		**590.0**	**590.0**	**595.2**	**600.7**	**600.8**	**601.1**	**602.0**	**601.6**	**600.6**	**588.7**	**588.7**	**588.9**
Electrical District 2 Firm		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Mesa 15 Firm		15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**	**123.0**
Adjusted Existing Resource Capacity		**467.0**	**467.0**	**472.2**	**477.7**	**477.8**	**478.1**	**479.0**	**478.6**	**477.6**	**465.7**	**465.7**	**465.9**
Power Sales Losses 2.97%		3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
% Reserves Required (SRSG Methodology)		14.8%	15.8%	18.0%	20.1%	18.7%	16.3%	14.8%	13.6%	14.0%	16.6%	18.5%	16.4%
Power Sales Reserves @ > of 12% or SRSG		18.2	19.4	22.2	24.7	23.0	20.1	18.3	16.7	17.2	20.4	22.8	20.2
Net Existing Resource Capacity		**445.1**	**443.9**	**446.4**	**449.4**	**451.1**	**454.3**	**457.1**	**458.2**	**456.7**	**441.6**	**439.3**	**442.1**
Additional Resources - PGR PPA		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		141.1	140.7	141.5	142.5	143.0	144.0	144.9	145.2	144.8	140.0	139.3	140.1
Sulphur Reserves @ > of 12% or SRSG		17.7	18.7	21.1	23.2	22.0	19.7	18.3	16.9	17.3	19.4	21.2	19.2
Sulphur Losses @ 2.97%		3.6	3.5	3.5	3.4	3.5	3.6	3.7	3.7	3.7	3.5	3.4	3.5
Partial Requirements Allocated Capacity (Sulphur)		**119.8**	**118.5**	**117.0**	**115.8**	**117.5**	**120.7**	**123.0**	**124.6**	**123.8**	**117.1**	**114.6**	**117.4**
Sulphur 2004 Final TRS NC Peak		116.7	116.6	108.6	116.9	141.8	159.3	161.0	157.2	141.0	118.0	113.1	118.8
Sulphur Surplus (Deficiency)		**3.1**	**1.9**	**8.4**	**(1.1)**	**(24.3)**	**(38.6)**	**(38.0)**	**(32.6)**	**(17.2)**	**(0.9)**	**1.5**	**(1.4)**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2009

All Values in MW Unless Indicated	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP ** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis ** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources	**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Electrical District 2 Firm	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Mesa 15 Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 17.5 Contingent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0
Total Other Contingent Loads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources	**108.0**	**108.0**	**108.0**	**108.0**	**108.0**	**108.0**	**108.0**	**108.0**	**108.0**	**108.0**	**108.0**	**108.0**
Adjusted Existing Resource Capacity	**465.9**	**465.8**	**470.8**	**476.3**	**476.3**	**476.7**	**477.6**	**477.1**	**476.2**	**465.7**	**465.7**	**465.9**
Power Sales Losses 2.97%	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
% Reserves Required (SRSG Methodology)	15.1%	16.2%	18.7%	20.8%	19.1%	16.6%	15.1%	13.8%	14.2%	17.0%	19.0%	16.8%
Power Sales Reserves @ > of 12% or SRSG	16.3	17.5	20.2	22.4	20.6	17.9	16.3	14.9	15.3	18.3	20.6	18.1
Net Existing Resource Capacity	**446.4**	**445.2**	**447.4**	**450.7**	**452.5**	**455.5**	**458.1**	**459.1**	**457.6**	**444.2**	**442.0**	**444.6**
Additional Resources - PGR PPA	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional	141.5	141.1	141.8	142.9	143.4	144.4	145.2	145.5	145.1	140.8	140.1	140.9
Sulphur Reserves @ > of 12% or SRSG	18.1	19.2	21.8	24.0	22.4	20.1	18.5	17.1	17.6	19.9	21.9	19.8
Sulphur Losses @ 2.97%	3.6	3.5	3.5	3.4	3.5	3.6	3.7	3.7	3.7	3.5	3.4	3.5
Partial Requirements Allocated Capacity (Sulphur)	**119.8**	**118.4**	**116.6**	**115.5**	**117.5**	**120.8**	**123.1**	**124.7**	**123.8**	**117.4**	**114.8**	**117.7**
Sulphur 2004 Final TRS NC Peak	120.0	120.1	111.7	120.2	145.7	163.7	165.3	161.3	144.8	121.4	116.4	122.1
Sulphur Surplus (Deficiency)	**(0.2)**	**(1.6)**	**4.9**	**(4.7)**	**(28.2)**	**(42.9)**	**(42.2)**	**(36.7)**	**(20.9)**	**(4.0)**	**(1.6)**	**(4.4)**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2010

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources		573.9	573.8	578.8	584.3	584.3	584.7	585.6	585.1	584.2	573.7	573.7	573.9
Electrical District 2 Firm		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Mesa 15 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0
Adjusted Existing Resource Capacity		465.9	465.8	470.8	476.3	476.3	476.7	477.6	477.1	476.2	465.7	465.7	465.9
Power Sales Losses 2.97%		3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
% Reserves Required (SRSG Methodology)		15.4%	16.4%	18.7%	20.8%	19.3%	16.8%	15.2%	13.9%	14.3%	17.2%	19.3%	17.1%
Power Sales Reserves @ > of 12% or SRSG		16.6	17.7	20.2	22.5	20.8	18.1	16.4	15.0	15.5	18.6	20.9	18.4
Net Existing Resource Capacity		446.1	444.9	447.4	450.6	452.3	455.4	458.0	459.0	457.5	443.9	441.6	444.3
Additional Resources - PGR PPA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		141.4	141.0	141.8	142.8	143.4	144.3	145.2	145.5	145.0	140.7	140.0	140.8
Sulphur Reserves @ > of 12% or SRSG		18.4	19.4	21.8	24.0	22.6	20.2	18.7	17.3	17.7	20.2	22.1	20.0
Sulphur Losses @ 2.97%		3.5	3.5	3.5	3.4	3.5	3.6	3.6	3.7	3.7	3.5	3.4	3.5
Partial Requirements Allocated Capacity (Sulphur)		119.5	118.1	116.5	115.4	117.3	120.6	122.9	124.5	123.6	117.1	114.5	117.3
Sulphur 2004 Final TRS NC Peak		123.3	123.6	114.9	123.5	149.7	168.2	169.8	165.7	148.8	125.2	120.1	125.7
Sulphur Surplus (Deficiency)		(3.8)	(5.5)	1.6	(8.1)	(32.5)	(47.6)	(46.9)	(41.1)	(25.2)	(8.1)	(5.6)	(8.3)

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2011

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Electrical District 2 Firm		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 15 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**
Adjusted Existing Resource Capacity		**565.9**	**565.8**	**570.8**	**576.3**	**576.3**	**576.7**	**577.6**	**577.1**	**576.2**	**565.7**	**565.7**	**565.9**
Power Sales Losses 2.97%		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
% Reserves Required (SRSG Methodology)		17.0%	18.3%	21.8%	24.2%	20.6%	17.5%	15.7%	14.2%	14.8%	18.6%	21.8%	18.7%
Power Sales Reserves @ > of 12% or SRSG		1.4	1.5	1.7	1.9	1.6	1.4	1.3	1.1	1.2	1.5	1.7	1.5
Net Existing Resource Capacity		**564.3**	**564.1**	**568.8**	**574.1**	**574.5**	**575.0**	**576.1**	**575.8**	**574.7**	**564.0**	**563.7**	**564.2**
Additional Resources - PGR PPA		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		178.9	178.8	180.3	182.0	182.1	182.3	182.6	182.5	182.2	178.8	178.7	178.8
Sulphur Reserves @ > of 12% or SRSG		25.4	27.0	31.6	34.7	30.3	26.5	24.2	22.1	22.9	27.3	31.2	27.5
Sulphur Losses @ 2.97%		4.4	4.4	4.3	4.2	4.4	4.5	4.6	4.6	4.6	4.4	4.3	4.4
Partial Requirements Allocated Capacity (Sulphur)		**149.1**	**147.4**	**144.5**	**143.1**	**147.4**	**151.3**	**153.9**	**155.8**	**154.7**	**147.1**	**143.2**	**147.0**
Sulphur 2004 Final TRS NC Peak		126.9	127.4	118.3	127.0	153.9	172.8	174.3	170.0	152.8	128.8	123.7	129.1
Sulphur Surplus (Deficiency)		**22.2**	**20.1**	**26.2**	**16.0**	**(6.5)**	**(21.5)**	**(20.4)**	**(14.2)**	**2.0**	**18.2**	**19.5**	**17.8**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2012

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Electrical District 2 Firm		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Salt River Project Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 15 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**
Adjusted Existing Resource Capacity		**565.9**	**565.8**	**570.8**	**576.3**	**576.3**	**576.7**	**577.6**	**577.1**	**576.2**	**565.7**	**565.7**	**565.9**
Power Sales Losses 2.97%		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
% Reserves Required (SRSG Methodology)		17.2%	18.5%	22.2%	24.5%	20.8%	17.7%	15.9%	14.3%	14.9%	18.8%	22.1%	18.9%
Power Sales Reserves @ > of 12% or SRSG		1.4	1.5	1.8	2.0	1.7	1.4	1.3	1.1	1.2	1.5	1.8	1.5
Net Existing Resource Capacity		**564.3**	**564.1**	**568.8**	**574.1**	**574.4**	**575.0**	**576.1**	**575.8**	**574.7**	**564.0**	**563.7**	**564.1**
Additional Resources - PGR PPA		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		178.9	178.8	180.3	182.0	182.1	182.3	182.6	182.5	182.2	178.8	178.7	178.8
Sulphur Reserves @ > of 12% or SRSG		25.6	27.3	32.0	35.0	30.7	26.8	24.4	22.3	23.1	27.6	31.6	27.8
Sulphur Losses @ 2.97%		4.4	4.4	4.3	4.2	4.4	4.5	4.6	4.6	4.6	4.4	4.2	4.4
Partial Requirements Allocated Capacity (Sulphur)		**148.9**	**147.2**	**144.0**	**142.7**	**147.1**	**151.0**	**153.7**	**155.6**	**154.5**	**146.9**	**142.9**	**146.7**
Sulphur 2004 Final TRS NC Peak		130.3	131.0	121.6	130.4	157.9	177.3	178.8	174.2	156.7	132.5	127.2	132.5
Sulphur Surplus (Deficiency)		**18.6**	**16.2**	**22.4**	**12.3**	**(10.8)**	**(26.2)**	**(25.1)**	**(18.6)**	**(2.2)**	**14.4**	**15.7**	**14.2**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2013

All Values in MW Unless Indicated	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP ** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis ** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources	**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Electrical District 2 Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 15 Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 17.5 Contingent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Contingent Loads	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Adjusted Existing Resource Capacity	**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Power Sales Losses 2.97%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
% Reserves Required (SRSG Methodology)	17.2%	18.5%	22.1%	24.5%	21.0%	17.9%	16.0%	14.5%	15.1%	18.8%	22.1%	18.9%
Power Sales Reserves @ > of 12% or SRSG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity	**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Additional Resources - PGR PPA	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional	181.9	181.9	183.5	185.2	185.2	185.3	185.6	185.5	185.2	181.9	181.9	181.9
Sulphur Reserves @ > of 12% or SRSG	26.0	27.7	32.5	35.6	31.4	27.4	25.0	22.8	23.6	28.1	32.2	28.3
Sulphur Losses @ 2.97%	4.5	4.4	4.4	4.3	4.4	4.6	4.6	4.7	4.7	4.4	4.3	4.4
Partial Requirements Allocated Capacity (Sulphur)	**151.4**	**149.8**	**146.7**	**145.3**	**149.4**	**153.4**	**156.0**	**158.0**	**156.9**	**149.4**	**145.4**	**149.2**
Sulphur 2004 Final TRS NC Peak	133.6	134.4	124.6	133.5	161.5	181.3	182.7	178.2	160.4	135.8	130.4	135.8
Sulphur Surplus (Deficiency)	**17.8**	**15.3**	**22.0**	**11.8**	**(12.2)**	**(28.0)**	**(26.7)**	**(20.2)**	**(3.6)**	**13.6**	**15.0**	**13.5**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2014

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Electrical District 2 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 15 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Adjusted Existing Resource Capacity		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Power Sales Losses 2.97%		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
% Reserves Required (SRSG Methodology)		17.1%	18.5%	22.1%	24.5%	21.2%	18.0%	16.1%	14.5%	15.2%	19.0%	22.1%	19.0%
Power Sales Reserves @ > of 12% or SRSG		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Additional Resources - PGR PPA		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		181.9	181.9	183.5	185.2	185.2	185.3	185.6	185.5	185.2	181.9	181.9	181.9
Sulphur Reserves @ > of 12% or SRSG		25.9	27.7	32.5	35.6	31.6	27.6	25.1	23.0	23.8	28.3	32.2	28.3
Sulphur Losses @ 2.97%		4.5	4.4	4.4	4.3	4.4	4.6	4.6	4.7	4.7	4.4	4.3	4.4
Partial Requirements Allocated Capacity (Sulphur)		**151.5**	**149.8**	**146.7**	**145.3**	**149.2**	**153.2**	**155.9**	**157.8**	**156.7**	**149.1**	**145.4**	**149.2**
Sulphur 2004 Final TRS NC Peak		136.9	137.8	127.6	136.6	165.2	185.4	186.7	182.1	164.2	139.2	133.6	139.0
Sulphur Surplus (Deficiency)		**14.6**	**12.0**	**19.0**	**8.7**	**(16.0)**	**(32.2)**	**(30.8)**	**(24.3)**	**(7.5)**	**9.9**	**11.7**	**10.2**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2015

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Electrical District 2 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 15 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Adjusted Existing Resource Capacity		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Power Sales Losses 2.97%		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
% Reserves Required (SRSG Methodology)		17.1%	18.4%	22.1%	24.5%	21.4%	18.1%	16.2%	14.6%	15.3%	19.2%	22.1%	19.2%
Power Sales Reserves @ > of 12% or SRSG		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Additional Resources - PGR PPA		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		181.9	181.9	183.5	185.2	185.2	185.3	185.6	185.5	185.2	181.9	181.9	181.9
Sulphur Reserves @ > of 12% or SRSG		25.9	27.6	32.4	35.6	31.8	27.7	25.3	23.1	24.0	28.6	32.2	28.6
Sulphur Losses @ 2.97%		4.5	4.4	4.4	4.3	4.4	4.5	4.6	4.7	4.6	4.4	4.3	4.4
Partial Requirements Allocated Capacity (Sulphur)		**151.5**	**149.8**	**146.7**	**145.3**	**149.0**	**153.1**	**155.8**	**157.7**	**156.6**	**148.9**	**145.4**	**148.9**
Sulphur 2004 Final TRS NC Peak		140.2	141.2	130.6	139.6	168.7	189.4	190.6	186.0	167.8	142.4	136.7	142.1
Sulphur Surplus (Deficiency)		**11.3**	**8.6**	**16.1**	**5.7**	**(19.8)**	**(36.4)**	**(34.8)**	**(28.2)**	**(11.3)**	**6.5**	**8.7**	**6.8**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2016

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Electrical District 2 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 15 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Adjusted Existing Resource Capacity		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Power Sales Losses 2.97%		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
% Reserves Required (SRSG Methodology)		17.3%	18.6%	22.1%	24.4%	21.5%	18.2%	16.3%	14.7%	15.4%	19.4%	22.3%	19.4%
Power Sales Reserves @ > of 12% or SRSG		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Additional Resources - PGR PPA		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		181.9	181.9	183.5	185.2	185.2	185.3	185.6	185.5	185.2	181.9	181.9	181.9
Sulphur Reserves @ > of 12% or SRSG		26.2	27.9	32.4	35.5	32.0	27.9	25.4	23.2	24.1	28.8	32.4	28.9
Sulphur Losses @ 2.97%		4.5	4.4	4.4	4.3	4.4	4.5	4.6	4.7	4.6	4.4	4.3	4.4
Partial Requirements Allocated Capacity (Sulphur)		**151.2**	**149.6**	**146.7**	**145.4**	**148.8**	**152.9**	**155.6**	**157.6**	**156.4**	**148.6**	**145.2**	**148.6**
Sulphur 2004 Final TRS NC Peak		143.3	144.5	133.6	142.7	172.3	193.5	194.6	189.9	171.6	145.8	140.0	145.5
Sulphur Surplus (Deficiency)		**7.9**	**5.1**	**13.1**	**2.7**	**(23.5)**	**(40.5)**	**(38.9)**	**(32.3)**	**(15.2)**	**2.8**	**5.1**	**3.1**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2017

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources		573.9	573.8	578.8	584.3	584.3	584.7	585.6	585.1	584.2	573.7	573.7	573.9
Electrical District 2 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 15 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adjusted Existing Resource Capacity		573.9	573.8	578.8	584.3	584.3	584.7	585.6	585.1	584.2	573.7	573.7	573.9
Power Sales Losses 2.97%		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
% Reserves Required (SRSG Methodology)		17.5%	18.9%	22.1%	24.4%	21.7%	18.4%	16.4%	14.8%	15.5%	19.6%	22.6%	19.6%
Power Sales Reserves @ > of 12% or SRSG		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity		573.9	573.8	578.8	584.3	584.3	584.7	585.6	585.1	584.2	573.7	573.7	573.9
Additional Resources - PGR PPA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		181.9	181.9	183.5	185.2	185.2	185.3	185.6	185.5	185.2	181.9	181.9	181.9
Sulphur Reserves @ > of 12% or SRSG		26.5	28.2	32.4	35.5	32.2	28.0	25.5	23.3	24.3	29.1	32.7	29.1
Sulphur Losses @ 2.97%		4.5	4.4	4.4	4.3	4.4	4.5	4.6	4.7	4.6	4.4	4.3	4.4
Partial Requirements Allocated Capacity (Sulphur)		151.0	149.3	146.7	145.4	148.6	152.8	155.5	157.5	156.3	148.4	144.9	148.4
Sulphur 2004 Final TRS NC Peak		146.7	148.0	136.7	145.9	176.1	197.6	198.7	194.0	175.5	149.3	143.4	148.9
Sulphur Surplus (Deficiency)		4.3	1.3	10.0	(0.5)	(27.5)	(44.9)	(43.2)	(36.5)	(19.3)	(0.9)	1.5	(0.5)

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2018

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Electrical District 2 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 15 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Adjusted Existing Resource Capacity		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Power Sales Losses 2.97%		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
% Reserves Required (SRSG Methodology)		17.7%	19.1%	22.1%	24.4%	21.8%	18.5%	16.5%	14.9%	15.6%	19.8%	22.8%	19.9%
Power Sales Reserves @ > of 12% or SRSG		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Additional Resources - PGR PPA		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		181.9	181.9	183.5	185.2	185.2	185.3	185.6	185.5	185.2	181.9	181.9	181.9
Sulphur Reserves @ > of 12% or SRSG		26.7	28.4	32.4	35.5	32.4	28.2	25.6	23.4	24.4	29.3	33.0	29.4
Sulphur Losses @ 2.97%		4.5	4.4	4.4	4.3	4.4	4.5	4.6	4.7	4.6	4.4	4.3	4.4
Partial Requirements Allocated Capacity (Sulphur)		**150.7**	**149.1**	**146.7**	**145.4**	**148.4**	**152.6**	**155.4**	**157.4**	**156.1**	**148.1**	**144.6**	**148.1**
Sulphur 2004 Final TRS NC Peak		150.1	151.6	139.8	149.1	179.8	201.9	202.8	198.1	179.4	152.8	146.8	152.3
Sulphur Surplus (Deficiency)		**0.6**	**(2.5)**	**6.9**	**(3.6)**	**(31.4)**	**(49.2)**	**(47.4)**	**(40.7)**	**(23.3)**	**(4.6)**	**(2.2)**	**(4.2)**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2019

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Electrical District 2 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 15 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Adjusted Existing Resource Capacity		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Power Sales Losses 2.97%		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
% Reserves Required (SRSG Methodology)		17.9%	19.2%	22.2%	24.6%	22.0%	18.6%	16.6%	15.0%	15.7%	20.0%	23.1%	20.1%
Power Sales Reserves @ > of 12% or SRSG		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity		**573.9**	**573.8**	**578.8**	**584.3**	**584.3**	**584.7**	**585.6**	**585.1**	**584.2**	**573.7**	**573.7**	**573.9**
Additional Resources - PGR PPA		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		181.9	181.9	183.5	185.2	185.2	185.3	185.6	185.5	185.2	181.9	181.9	181.9
Sulphur Reserves @ > of 12% or SRSG		27.0	28.6	32.6	35.7	32.6	28.3	25.8	23.5	24.5	29.6	33.3	29.7
Sulphur Losses @ 2.97%		4.5	4.4	4.4	4.3	4.4	4.5	4.6	4.7	4.6	4.4	4.3	4.4
Partial Requirements Allocated Capacity (Sulphur)		**150.5**	**148.8**	**146.6**	**145.2**	**148.3**	**152.5**	**155.3**	**157.3**	**156.0**	**147.9**	**144.3**	**147.8**
Sulphur 2004 Final TRS NC Peak		153.5	155.1	142.9	152.2	183.5	206.0	206.9	202.1	183.3	156.2	150.1	155.6
Sulphur Surplus (Deficiency)		**(3.0)**	**(6.3)**	**3.6**	**(7.0)**	**(35.3)**	**(53.5)**	**(51.6)**	**(44.8)**	**(27.2)**	**(8.2)**	**(5.7)**	**(7.8)**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2020

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
Apache GT-2		20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Apache GT-3		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources		573.9	573.8	578.8	584.3	584.3	584.7	585.6	585.1	584.2	573.7	573.7	573.9
Electrical District 2 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salt River Project Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 15 Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mesa 17.5 Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cyprus Contingent		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Morenci Water & Electric Firm		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Firm Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adjusted Existing Resource Capacity		573.9	573.8	578.8	584.3	584.3	584.7	585.6	585.1	584.2	573.7	573.7	573.9
Power Sales Losses 2.97%		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
% Reserves Required (SRSG Methodology)		18.1%	19.4%	22.4%	24.8%	22.1%	18.7%	16.7%	15.1%	15.8%	20.2%	23.3%	20.3%
Power Sales Reserves @ > of 12% or SRSG		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity		573.9	573.8	578.8	584.3	584.3	584.7	585.6	585.1	584.2	573.7	573.7	573.9
Additional Resources - PGR PPA		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		181.9	181.9	183.5	185.2	185.2	185.3	185.6	185.5	185.2	181.9	181.9	181.9
Sulphur Reserves @ > of 12% or SRSG		27.2	28.9	32.8	35.9	32.7	28.5	25.9	23.7	24.7	29.8	33.6	30.0
Sulphur Losses @ 2.97%		4.5	4.4	4.3	4.3	4.4	4.5	4.6	4.7	4.6	4.4	4.3	4.4
Partial Requirements Allocated Capacity (Sulphur)		150.3	148.6	146.3	145.0	148.1	152.4	155.1	157.2	155.9	147.7	144.0	147.6
Sulphur 2004 Final TRS NC Peak		156.9	158.7	146.1	155.5	187.4	210.4	211.2	206.4	187.4	160.0	153.7	159.3
Sulphur Surplus (Deficiency)		(6.7)	(10.1)	0.2	(10.5)	(39.3)	(58.0)	(56.0)	(49.3)	(31.5)	(12.3)	(9.7)	(11.7)

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.

Monthly Allocated Capacity for 2021 Through 2035

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Apache ST-2		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache ST-3		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Apache CC-1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
PacifiCorp		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service of New Mexico		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SLCA - IP	** Note 1 **	1.6	1.6	1.4	6.9	7.0	7.3	8.2	7.8	6.8	1.4	1.4	1.6
Parker-Davis	** Note 2 **	17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Existing Resources Remaining **Note 3**		**406.9**	**406.8**	**411.8**	**417.3**	**417.3**	**417.7**	**418.6**	**418.1**	**417.2**	**406.7**	**406.7**	**406.9**
Total Other Firm Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other Contingent Loads		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Sales		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Adjusted Existing Resource Capacity		**406.9**	**406.8**	**411.8**	**417.3**	**417.3**	**417.7**	**418.6**	**418.1**	**417.2**	**406.7**	**406.7**	**406.9**
Power Sales Losses 2.97%		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
% Reserves Required (SRSG Methodology)		18.3%	19.6%	22.7%	25.0%	22.3%	18.8%	16.8%	15.1%	15.9%	20.3%	23.5%	20.5%
Power Sales Reserves @ > of 12% or SRSG		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity		**406.9**	**406.8**	**411.8**	**417.3**	**417.3**	**417.7**	**418.6**	**418.1**	**417.2**	**406.7**	**406.7**	**406.9**
Additional Resources - PGR PPA		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mohave's ACP in Existing Resources = A %		35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%	35.8%
Remaining ACP Existing Resources = 100% - A = B %		64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%	64.2%
Sulphur ACP in Existing Resources = C %		31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Sulphur Share Additional Resources = C / B = D %		49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%
Sulphur Gross Capacity = C * Existing + D * Additional		129.0	129.0	130.5	132.3	132.3	132.4	132.7	132.5	132.2	128.9	128.9	129.0
Sulphur Reserves @ > of 12% or SRSG		19.5	20.7	23.6	25.8	23.5	20.4	18.6	17.0	17.7	21.3	24.0	21.4
Sulphur Losses @ 2.97%		3.2	3.1	3.1	3.1	3.1	3.2	3.3	3.3	3.3	3.1	3.0	3.1
Partial Requirements Allocated Capacity (Sulphur)		**106.4**	**105.2**	**103.9**	**103.4**	**105.6**	**108.7**	**110.8**	**112.2**	**111.2**	**104.6**	**101.9**	**104.5**

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is reduced 163 kW summer & 116 kW winter beginning 10-01-2008.
Note 3: Existing Resources Remaining means AEPCO Existing Resources as of the Restructuring Effective Date of 8/1/2001 that have not terminated or been retired as of 1/1/2021.

SCHEDULE B

TO PARTIAL REQUIREMENTS

CAPACITY AND ENERGY AGREEMENT

BETWEEN

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

AND

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.

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SCHEDULE B
MINIMUM AND MAXIMUM ENERGY TAKES

1. INTRODUCTION:

1.1 Purpose.

This Schedule B establishes the amount of energy to be available to Sulphur Springs Valley Electric Cooperative, Inc. (SSVEC or Member) for purchase pursuant to the Partial Requirements Capacity and Energy Agreement, entered into between Arizona Electric Power Cooperative, Inc. (AEPCO) and Member (Agreement), from SSVEC's AC in AEPCO Resources at the energy rate set forth in Exhibit A-1 to Rate Schedule A. Such amount is based upon the ACP and AC of SSVEC and the historical use of AEPCO Resources to serve SSVEC Total Load. In addition, this Schedule B specifies the methodology pursuant to which additional charges shall be made by AEPCO to SSVEC in the event that: 1) SSVEC requires capacity and/or energy from AEPCO Resources that is in excess of the amount of its AC in AEPCO Resources and in excess of the energy available to SSVEC associated with its AC in AEPCO Resources at the energy rate of Exhibit A-1 to Rate Schedule A, both as determined herein; or 2) SSVEC does not take its required minimum capacity and energy from AEPCO Resources because SSVEC has used energy from other sources that displaces the use of such minimum energy from AEPCO Resources. Such additional charges shall be billed to SSVEC pursuant to Rate Schedule A.

The Parties intend that the results to SSVEC of this Schedule B shall be consistent with the results to MEC of Schedule B to the MEC Partial Requirements Capacity and Energy Agreement.

1.2 Objective.

The objective of this Schedule B is to: 1) maintain minimum energy production from AEPCO's base-load, coal-fired units (Apache Units 2 and 3) in off-peak or light load periods that could otherwise be decreased by SSVEC's purchase of certain supplemental capacity and energy for its Total Load; 2) minimize imposing increased energy costs on AEPCO resulting from more frequent and increased use of gas-fired peaking and gas-fired steam units in peak or heavy load periods that may result from certain sales by SSVEC from its AC; and 3) minimize imposing on AEPCO increased maintenance costs and possible loss of life of Generating Resources of AEPCO.

1.3 Definitions.

All capitalized terms used and not defined in this Agreement, including this Schedule B, shall have the respective meanings as set forth in Appendix A to the Agreement.

"AC Ratio" shall mean the ratio of the AC of SSVEC for a month of a year subsequent to 2001 as compared to the AC of SSVEC for the corresponding month of 2001.

"AEPCO Delivered Load Without MEC" shall mean AEPCO Delivered Load less MEC Historic Total Load.

"AEPCO Maximum Base Capacity" shall mean that amount of capacity on an hourly basis equal to the sum of AEPCO Maximum Coal Capacity plus AEPCO Must-Run Purchase Capacity.

"AEPCO Maximum Coal Capacity" shall mean that amount of capacity on an hourly basis equal to the maximum net rated output of Apache Units 2 and 3, which is a total of 350 MW from both such units, or 175 MW from each such unit individually.

"AEPCO Minimum Base Capacity" shall mean that amount of capacity on an hourly basis equal to the sum of AEPCO Minimum Coal Capacity, plus AEPCO Must-Run Purchase Capacity.

"AEPCO Minimum Coal Capacity" shall mean that amount of capacity on an hourly basis equal to the minimum output for safe and reliable operation of Apache Units 2 and 3 which totals 210 MW from both such units, or 105 MW from each unit individually.

"AEPCO Must-Run Purchase Capacity" shall mean that amount of capacity on an hourly basis equal to the sum of the seasonal or monthly capacity amount available to AEPCO pursuant to Federal Hydro Power Agreements, plus the monthly capacity amount which must be taken or paid for by AEPCO pursuant to any purchase power agreement in which SSVEC has an ACP, as such amounts are in effect in Off-Peak Hours or Peak Hours, as applicable.

"Allocated Capacity Deficiency" shall mean that amount of capacity by which the AC of SSVEC is insufficient to meet the demand of the Net Total Load of SSVEC.

"Allocated Capacity Excess" shall mean that amount of capacity by which the AC of SSVEC exceeds the sum of the coincident demands of SSVEC AEPCO Load and SSVEC AEPCO Sales.

"Average Daily Load Curve(s)" shall mean the profile of the average hourly demands of SSVEC Historic Total Load for the period 1995 through 1999, which profile is in the form of an integrated curve over a twenty-four (24) hour day.

"Class A Historic Total Load Without MEC" shall mean the sum of SSVEC Historic Total Load plus Total Historic Load of All Requirements Members, excluding MEC Historic Total Load.

"Federal Hydro Power Agreement(s)" shall consist of the following contracts:

a) Contract No. 87-BCA-10001 for Firm Electric Service between Western Area Power Administration and Arizona Power Pooling Association, dated March 9, 1989; Amendment No. 1, dated March 9, 1989; Amendment No. 2, dated December 29, 1989; Amendment No. 3, dated June 9, 1992; and Amendment No. 4, dated March 5, 1997; Amendment No. 5, dated August 20, 1999; and as it may be amended from time to time, and its successor agreement(s) (SLCA Integrated Projects Agreement); and

b) Contract No. 87-BCA-10085 Electric Service between Western Area Power Administration and Arizona Power Pooling Association, dated February 25, 1988, Amendment No. 1, dated __________; and as it may be amended from time to time, and its successor agreement(s) (Parker-Davis Project Agreement).

"MEC Historic Total Load" shall mean the historical totals of both the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of the loads located within Member's Distribution Service Area of MEC (or served from line extensions therefrom), the demand requirements of which shall be as set forth in Table B-1.1 of Schedule B to the MEC Partial Requirements Capacity and Energy Agreement as amended as of the Agreement Date.

"Schedule A Energy" shall mean the energy available to SSVEC from its AC in AEPCO Resources at the energy rate set forth in Exhibit A-1 to Rate Schedule A, as determined pursuant to Section 6.5 hereof.

"Schedule B Energy" shall mean energy available to SSVEC from its AC in AEPCO Resources in excess of Schedule A Energy, which is billed to SSVEC at the rates set forth in or determined pursuant to this Schedule B.

"SSVEC AEPCO Resource Profile" shall mean a profile of hourly capacity and energy from AEPCO Resources that is available to SSVEC over a twenty-four (24) hour day that is determined in accordance with Section 6 hereof.

"SSVEC AEPCO Profile Capacity" shall mean the portion of AC that is available to SSVEC in conjunction with SSVEC AEPCO Profile Energy.

"SSVEC AEPCO Profile Energy" shall mean the portion of Schedule A Energy that is derived from the SSVEC AEPCO Resource Profiles.

"SSVEC Historic Total Load" or "SSVEC's Historic Total Load" shall mean, for purposes of this Schedule B, the historical totals of both the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of the loads located within the Member's Distribution Service Area of SSVEC (or served from line extensions therefrom), the demand requirements of which shall be as set forth in Table B-1.1 hereof.

"Total Historic Load of All Requirements Members" shall mean, for purposes of this Schedule B, the sum of the historical totals of both the demands and energy requirements served from AEPCO Resources of each of the All Requirements Members, excluding reserves and transmission losses, which shall be as set forth in Table B-1.1 hereof for purposes of this Schedule B.

2. SSVEC'S HISTORIC USE OF AEPCO RESOURCES:

2.1 Demand Coincident with All Requirements Members.

The 1995 through 1999 monthly demands of SSVEC Historic Total Load and the Total Historic Load of All Requirements Members coincident with AEPCO Member Peak Demand, and the average of such demands over such period, are set forth in Table B-1.1, attached hereto. Such average demands of each month for SSVEC and for the All Requirements Members set forth in Table B-1.1 shall be used in this Schedule B in the determination of the respective shares of SSVEC and the All Requirements Members in: (i) AEPCO Minimum Coal Capacity; (ii) AEPCO Must-Run Purchase Capacity; and (iii) AEPCO Maximum Coal Capacity. The similar shares of MEC in such capacities are set forth in Schedule B to the MEC Partial Requirements Capacity and Energy Agreement.

2.2 SSVEC's Individual Peak and Monthly Energy.

Table B-1.2 attached hereto sets forth: (i) the monthly 1995 through 1999 demands and the average demand of SSVEC Historic Total Load at the times of peak demand of SSVEC's system; and (ii) the monthly energy consumed by SSVEC Historic Total Load during the 1995 through 1999 period and the average monthly amount thereof. These average monthly demand and energy data shall be used in the determination of the monthly amounts of capacity and energy to be available to SSVEC from AEPCO Resources pursuant to Section 6 hereof at the rates and Fixed Charge set forth in Exhibit A-1 to Rate Schedule A. The Table B-1.2 data for MEC is determined similarly in Schedule B to the MEC Partial Requirements Capacity and Energy Agreement.

2.3 The provisions of this Section 2 shall be null and of no further force and effect for the period beginning on January 1, 2021.

3. SSVEC ACTIVITIES RELATED TO ALLOCATED CAPACITY DEFICIENCY AND EXCESS:

3.1 Allocated Capacity Deficiency.

If SSVEC is utilizing a supply of energy supplemental to that available from the AC of SSVEC and is not taking its required share of AEPCO Minimum Base Capacity, SSVEC shall pay a charge as set forth in Section 7.2.2 hereof.

3.2 Allocated Capacity Excess.

Pursuant to the Agreement, SSVEC has the right to use energy from its Allocated Capacity Excess. To the extent that such energy is provided from SSVEC's share of AEPCO Maximum Base Capacity (as determined in accordance with Section 5.3 hereof), SSVEC shall be billed and pay for such capacity and energy at the O&M and energy rates set forth in Exhibit A-1 to Rate Schedule A to the Agreement. To the extent that such energy is provided from other AEPCO Resources (as determined pursuant to Section 6 hereof), SSVEC shall be billed and pay for such capacity pursuant to Rate Schedule A, and for such energy pursuant to Section 7.2.3 hereof.

4. AEPCO MINIMUM BASE CAPACITY:

4.1 Mutual Cooperation.

AEPCO has in the past experienced and may in the future encounter minimum loading problems on the Apache Units 2 and 3 during periods of lower loads. Such minimum loading problems may arise in part because of the requirements of certain Power Purchase Resources of AEPCO to schedule and use energy during such periods. Purchases of supplemental energy by SSVEC during such load periods may aggravate this problem. In order to avoid aggravating this minimum loading problem, SSVEC shall share in minimum energy obligations with respect to the Apache Units 2 and 3 and the must-run requirements of certain Power Purchase Resources of AEPCO during such periods. AEPCO shall be responsible for similar minimum energy obligations determined for All Requirements Members and Power Sales Loads. MEC's share in such minimum energy obligations and must-run requirements is determined pursuant to Schedule B to the MEC Partial Requirements Capacity and Energy Agreement.

4.2 AEPCO Minimum Coal Capacity.

Attached hereto as Table B-2 is the tabulation of AEPCO Minimum Coal Capacity, which shall be a portion of AEPCO Minimum Base Capacity, and which shall be allocated among SSVEC, MEC, All Requirements Members and certain Power Sales Loads. Table B-2 illustrates the result of the methodology set forth in Section 4.2.1 below to allocate AEPCO Minimum Coal Capacity, and sets forth SSVEC's share thereof. The monthly contract demands of such Power Sales Loads and the actual average of the monthly peak demands of the Total Historic Load of All Requirements Members and of SSVEC Historic Total Load as set forth in Table B-1.1, and the MEC share of AEPCO Minimum Coal Capacity as set forth in Schedule B to the MEC Partial Requirements Capacity and Energy Agreement, are utilized to produce the results displayed in Table B-2.

4.2.1 Methodology. The methodology hereunder utilizes defined terms which are used in the captions of Table B-2 as clarified in Attachment A hereto.

4.2.1.1 Class A Historic Total Load Without MEC is calculated by adding the average demands of the Total Historic Load of All

Requirements Members from Table B-1.1, to the average demands of SSVEC Historic Total Load from Table B-1.1 for the same month.

4.2.1.2 The contract demands of all Power Sales Loads except for any Power Sale Loads that obligate the purchaser to a share of AEPCO Minimum Coal Capacity (as of the Agreement Date, no such Power Sale Load exists) shall be added to provide Power Sales Load.

4.2.1.3 Class A Historic Total Load Without MEC shall be added to Power Sales Load to provide AEPCO Delivered Load Without MEC.

4.2.1.4 The allocation percentage shares for Power Sales Load and Class A Historic Total Load Without MEC as percentages of AEPCO Delivered Load Without MEC shall be calculated.

4.2.1.5 The contractually determined capacity share allocated as MEC share of AEPCO Minimum Coal Capacity is subtracted from the 210 MW of AEPCO Minimum Coal Capacity to determine the remaining capacity of AEPCO Minimum Coal Capacity to be allocated between Power Sales Load and Class A Historic Total Load Without MEC (the "Remaining Minimum Coal Capacity"). Such Remaining Minimum Coal Capacity shall be multiplied by the percentage shares determined in Section 4.2.1.4 hereof, to determine the Remaining Minimum Coal Capacity allocated to Power Sales Load and the Remaining Minimum Load Capacity allocated to Class A Historic Total Load Without MEC.

4.2.1.6 SSVEC's monthly share of the AEPCO Minimum Coal Capacity shall be the product of: (i) the quotient found by dividing (a) ACP of SSVEC by (b) the difference obtained by subtracting the ACP of MEC from 100%; multiplied by (ii) the Remaining Minimum Coal Capacity allocated to Class A Historic Total Load Without MEC determined in Section 4.2.1.5 hereof.

4.2.2 Beginning January 1, 2021, SSVEC's monthly share of the AEPCO Minimum Coal Capacity shall be the product of the ACP of SSVEC multiplied by AEPCO Minimum Coal Capacity.

4.3 <u>AEPCO Must-Run Purchase Capacity</u>.

AEPCO Must-Run Purchase Capacity shall be a portion of AEPCO Minimum Base Capacity, and shall be allocated among the Total Historic Load of All Requirements Members, SSVEC Historic Total Load, and MEC Historic Total Load and certain Power Sales Loads in accordance with this Section 4.3. Tables B-3, B-3.1 and B-3.2 attached hereto: (i) are the initial tabulation of the results of such allocation; (ii) illustrate the methodology of allocation, and (iii) set forth SSVEC's share of AEPCO Must-Run Purchase Capacity for 2004. AEPCO Must-Run Purchase

Capacity shall be stated separately for Peak Hours and Off-Peak Hours. The component of AEPCO Must-Run Purchase Capacity from Federal Hydro Power Agreements shall be determined in accordance with Section 4.3.1 below. The component of AEPCO Must-Run Purchase Capacity from any power purchase agreement in which SSVEC has an ACP shall be determined in accordance with Section 4.3.2 below. MEC's share of the components of AEPCO Must-Run Purchase Capacity is determined pursuant to Schedule B to the MEC Partial Requirements and Energy Agreements.

4.3.1 <u>Must-Run from Federal Hydro Power Agreements</u>.

4.3.1.1 For each month, SSVEC's share of AEPCO Must-Run Purchase Capacity from Federal Hydro Power Agreements shall be the product of SSVEC's ACP multiplied by the amount of AEPCO Must-Run Purchase Capacity from the Federal Hydro Power Purchase Agreements. The amount of the component of AEPCO Must-Run Purchase Capacity from the Federal Hydro Power Agreements for Off-Peak Hours and for Peak Hours shall be determined pursuant to Sections 4.3.1.2 and 4.3.1.3 hereof, respectively.

4.3.1.2 For Off-Peak Hours, the component of AEPCO Must-Run Purchase Capacity from the Federal Hydro Power Agreements shall be as established by the respective project agreements. The Parker-Davis Project Agreement currently establishes such capacity in Off-Peak Hours as twenty-five (25%) percent of the energy available to AEPCO in each month divided by the number of Off-Peak Hours occurring in such month. The SLCA Integrated Projects Agreement currently establishes such capacity in Off-Peak Hours as thirty-five (35%) percent of the Contract Rate of Delivery (as such term is defined in the SLCA Integrated Projects Agreement).

4.3.1.3 For Peak Hours, the component of AEPCO Must-Run Purchase Capacity from the Federal Hydro Power Agreements is established as the lesser of AEPCO's Contract Rate of Delivery (as defined in the respective project agreement) or the highest rate of delivery established by Western pursuant to the respective project agreements as set forth in writing and provided to AEPCO by Western.

4.3.1.4 Table B-3.1 attached illustrates for year 2004 the component of AEPCO Must-Run Purchase Capacity from Federal Hydro Power Agreements and SSVEC's share thereof.

4.3.1.5 In the event that, during the term of this Agreement, SSVEC receives, pursuant to a contract between SSVEC and Western Area Power Administration (Western), an individual allocation of Federal Hydro Power from either or both of the SLCA Integrated Projects and the Parker-Davis Project (the "Affected Project(s)"), then SSVEC's share of AEPCO Must-Run Purchase Capacity from Federal Hydro Power Agreements from an Affected Project in which SSVEC receives such an individual allocation shall be: (i) the positive amount, if any, resulting from subtracting such SSVEC individual allocation from the product of SSVEC's ACP multiplied by AEPCO Must-Run Purchase Capacity from Federal Hydro Power Agreements for such Affected Project; or, (ii) if AEPCO is advised in writing by Western that AEPCO Must-Run Purchase Capacity from Federal Hydro Power Agreements for such Affected Project has been reduced in order for SSVEC to receive an individual allocation, SSVEC's share of AEPCO Must-Run Purchase Capacity from Federal Hydro Power Agreements for such Affected Project shall be zero. Such modification of SSVEC's share of AEPCO Must-Run Purchase Capacity from Federal Hydro Power Agreements shall be deemed to be a Minor Resource Modification for the purposes of the Agreement. As soon as practicable following notification to AEPCO by SSVEC of an SSVEC individual allocation in Affected Project(s), AEPCO shall prepare and provide to SSVEC the amount of SSVEC's share of AEPCO Must-Run Purchase Capacity from Federal Hydro Power Agreements resulting from this Section 4.3.1.5, as well as revised tables and exhibits reflecting such amount and the resulting AC of SSVEC for the purposes of (i) this Schedule B pursuant to Section 8 hereof; and (ii) the Agreement pursuant to Section 3.3.1.2 thereof, including Appendix B to Exhibit A-5 of Rate Schedule A. Such revised tables and exhibits shall be effective on the day that SSVEC first receives a delivery of Federal Hydro Power pursuant to the contract between SSVEC and Western.

4.3.2 Must-Run from Any Power Purchase Agreement.

4.3.2.1 The component of AEPCO Must-Run Purchase Capacity from any power purchase agreement in which SSVEC has an ACP shall be the monthly contract capacity set forth in such power purchase agreement. Such contract capacity shall be allocated between Class A Historic Total Load Without MEC and certain Power Sales Loads (set forth in Section 4.3.2.2) in the manner set forth in Table B-3.2, attached hereto. SSVEC's share of AEPCO Must-Run Purchase Capacity from any power purchase agreement in which SSVEC has an ACP is derived in Table B-3-2 as the product of: (i) the share of AEPCO Must-Run Purchase Capacity allocated to Class A Historic Total Load Without MEC; multiplied by (ii) the quotient found by dividing (a) SSVEC's ACP, by (b) the difference obtained by subtracting the ACP of MEC from 100%.

4.3.2.2 Table B-3.2 shall use the contract demands of Power Sales Loads that are not served exclusively from Apache Units 2 and 3 (captioned as "Power Sales Load Without Base" in Table B-3-2, and the sum of the historical average of the actual demands of the Total Historic Load of All Requirements Members, SSVEC Historic Total Load, as set forth in Table B-1.1 hereof, to allocate the contract demands of any power purchase agreement in which SSVEC has an ACP between Class A Historic Total Load Without MEC and such Power Sales Loads.

4.4 SSVEC's Share of AEPCO Minimum Base Capacity.

SSVEC's monthly share of AEPCO Minimum Base Capacity which SSVEC shall purchase from AEPCO pursuant to the Agreement, shall be the sum of SSVEC's share of AEPCO Minimum Coal Capacity (determined as set forth in Section 4.2 hereof), plus SSVEC's share of AEPCO Must-Run Purchase Capacity (determined as set forth in Section 4.3 hereof). Included in the data of Table B-7 is SSVEC's monthly share of AEPCO Minimum Base Capacity.

5. AEPCO MAXIMUM BASE CAPACITY:

5.1 Mutual Cooperation.

While operating above minimums, AEPCO has in the past experienced and may in the future encounter periods when it has capacity and energy available from Apache Units 2 and 3 and AEPCO Must-Run Purchase Capacity that is surplus to AEPCO Total Load. Pursuant to the Agreement, SSVEC has the right to sell its Allocated Capacity Excess. The exercise of such right could cause AEPCO to operate its Resources uneconomically, thereby detrimentally affecting the energy rates of the Class A Members. However, SSVEC's use of that portion of its Allocated Capacity Excess that is available from SSVEC's share of AEPCO Maximum Base Capacity could be beneficial. This Section 5 sets forth the method for determination of SSVEC's share of AEPCO Maximum Base Capacity. MEC's share of AEPCO Maximum Base Capacity is determined pursuant to Schedule B to the MEC Partial Requirements Capacity and Energy Agreement.

5.2 AEPCO Maximum Coal Capacity.

Attached hereto as Table B-4 is the tabulation of AEPCO Maximum Coal Capacity, which shall be a portion of AEPCO Maximum Base Capacity, and shall be allocated among SSVEC, MEC, All Requirements Members and certain Power Sales Loads. Table B-4 illustrates the result of the methodology set forth in Section 5.2.1 below to allocate AEPCO Maximum Coal Capacity, and sets forth SSVEC's share thereof. The monthly contract demands of certain Power Sales Loads and the monthly actual average peak demands of the Total Historic Load of All Requirements Members and of SSVEC Historic Total Load as set forth in Table B-1.1, and the MEC share of AEPCO Maximum Coal Capacity as set forth in Schedule B to the MEC Partial Requirements Capacity and Energy Agreement, shall be utilized to produce the results displayed in Table B-4.

5.2.1 Methodology. The methodology hereunder utilizes defined terms which are used in the captions of Table B-4 and clarified in Attachment A hereto.

5.2.1.1 Class A Historic Total Load Without MEC shall be determined in the same manner as set forth in Section 4.2.1.1 hereof.

5.2.1.2 The contract demands of all Power Sales Loads that do not have a share of AEPCO Maximum Coal Capacity and are not priced exclusively on costs of Apache Units 2 and 3 (as of the Agreement Date, the Power Sales Load of the 15.0 MW City of Mesa agreement) shall be added to provide Power Sales Load Without Share of Maximum Coal Capacity.

5.2.1.3 Class A Historic Total Load Without MEC shall be added to Power Sales Load Without Share of Maximum Coal Capacity to provide AEPCO Delivered Load Without MEC.

5.2.1.4 The allocation percentage shares for such Power Sales Load Without Share of Maximum Coal Capacity and Class A Historic Total Load Without MEC as percentages of AEPCO Delivered Load Without MEC shall be calculated.

5.2.1.5 The Power Sales Loads that have a share of AEPCO Maximum Coal Capacity and are priced exclusively on the costs of Apache Units 2 and 3 (as of the Agreement Date, the Power Sales Loads of, SRP, ED-2, and the MEC share of AEPCO Maximum Coal Capacity as set forth in Schedule B to the MEC Partial Requirements Capacity and Energy Agreement) shall then be subtracted from the 350 MW of AEPCO Maximum Coal Capacity to determine the remaining capacity of AEPCO Maximum Coal Capacity to be allocated between Power Sales Load Without Share of Maximum Coal Capacity and Class A Historic Total Load Without MEC (the "Remaining Maximum Coal Capacity"). Such Remaining Maximum Coal Capacity shall be multiplied by the percentage shares determined in Section 5.2.1.4 hereof, to determine the capacity share of Remaining Maximum Coal Capacity allocated to Power Sales Load Without Share of Maximum Coal Capacity and to Class A Historic Total Load Without MEC.

5.2.1.6 SSVEC's monthly share of AEPCO Maximum Coal Capacity shall be the product of: (i) the quotient found by dividing (a) the ACP of SSVEC by (b) the difference obtained by subtracting the ACP of MEC from 100%; multiplied by (ii) the capacity share of Remaining Maximum Coal Capacity allocated to Class A Total Load Without MEC determined in Section 5.2.1.5 hereof.

5.2.2 Beginning January 1, 2021, SSVEC's monthly share of AEPCO Maximum Coal Capacity shall be the product of the ACP of SSVEC multiplied by AEPCO Maximum Coal Capacity.

5.3 SSVEC's Share of AEPCO Maximum Base Capacity.

SSVEC's monthly share of such AEPCO Maximum Base Capacity shall be the sum of SSVEC's share of AEPCO Maximum Coal Capacity (determined as set forth in Section 5.2 hereof), plus SSVEC's share of AEPCO Must-Run Purchase Capacity, determined as set forth in Section 4.3 hereof. Included in the data of Table B-7 is SSVEC's monthly share of AEPCO Maximum Base Capacity.

6. AEPCO AND SSVEC CAPACITY AND ENERGY OBLIGATIONS:

6.1 Introduction.

Pursuant to the Agreement, AEPCO makes capacity and energy available to SSVEC for purchase in amounts up to SSVEC's AC and associated energy. This Section 6 establishes a maximum amount of Schedule A Energy available to SSVEC for purchase pursuant to the Agreement and establishes the SSVEC AEPCO Profile Capacity which is associated with Schedule A Energy. SSVEC shall pay for its use of Schedule B Energy at the rates and additional charges set forth in, and determined pursuant to, Section 7 hereof. SSVEC also may be subject to additional charges pursuant to Section 7.2.4 related to the failure of SSVEC to use its SSVEC AEPCO Profile Capacity. The methodology set forth hereunder in this Section 6 utilizes defined terms which are identified hereunder, or in the tables and exhibits appended hereto.

6.2 Average Daily Load Curves.

The aggregate amount of energy to be available to SSVEC for purchase under the Agreement as Schedule A Energy each month shall be determined from SSVEC's average historic use of energy from AEPCO Resources as set forth in Table B-1.2. Such Schedule A Energy shall be available each month to SSVEC in similar hours and patterns as SSVEC has historically used energy purchased from AEPCO, but the peak use of such energy shall not exceed AC.

6.2.1 The historic use by SSVEC of energy from AEPCO Resources is derived from the average of the 1995 through 1999 actual hourly SSVEC Historic Total Load. In order to summarize the historic patterns of use of such energy, five (5) Average Daily Load Curves (ADLC) for each month have been developed based upon such historical data, each such curve representing each hour's energy of each particular day of such month, as follows:

6.2.1.1 A Peak Day ADLC, which shall represent the day of the month of the highest demand of SSVEC Historic Total Load;

6.2.1.2 A Minimum Peak ADLC, which shall represent the day of the month of lowest peak demand during Peak Hours of SSVEC Historic Total Load;

6.2.1.3 A Non-Holiday Weekday ADLC, which shall represent the average of SSVEC Historic Total Load for all remaining weekdays of the month;

6.2.1.4 A Saturday ADLC, which shall represent the average of SSVEC Historic Total Load for all Saturdays of the month; and

6.2.1.5 A Sunday and Holiday ADLC, which shall represent the average of SSVEC Historic Total Load for all Sundays and Holidays occurring in the month.

6.2.2 Such ADLC's for each month developed for purposes of this Schedule B are set forth in the graphs of Exhibit B-1 attached hereto.

6.3 SSVEC AEPCO Resource Profiles.

The characteristics of the ADLC's of SSVEC are such that no adjustments are required to form SSVEC AEPCO Resource Profiles.

6.3.1 Five (5) corresponding SSVEC AEPCO Resource Profiles are constructed from the ADLC's by using the hourly demands of each ADLC to form corresponding SSVEC AEPCO Resource Profiles for 2001, which consist of a Peak Day Profile, a Minimum Peak Profile, a Non-Holiday Weekday Profile, a Saturday Profile, and a Sunday & Holiday Profile, which are attached as Exhibit B-2.

6.3.2 The SSVEC AEPCO Resource Profiles shall be used to obtain SSVEC AEPCO Profile Energy for each month of 2001 and each year pursuant to Sections 6.4 and 6.5 below, respectively.

6.3.3 The SSVEC AEPCO Profile Capacity for each month of 2001 shall equal the lesser of the AC for such month as set forth in Appendix B to Exhibit A-5 of Rate Schedule A, or the average peak demand for such month set forth in Table B-1.2. The SSVEC AEPCO Profile Capacity for each month of 2001 shall be as set forth as "2001 Resource Peak Demand" on Table B-5.1.

6.4 Determining Hourly Schedule A Energy Available in 2001.

The SSVEC AEPCO Resource Profiles developed pursuant to Section 6.3.1 hereof for each month shall be used to determine SSVEC AEPCO Profile Energy for each hour of each month of 2001, in accord with the following methodology:

6.4.1 The twenty-four (24) hourly amounts from the Peak Day Profile shall be used for one non-Holiday weekday of the month;

6.4.2 The twenty-four (24) hourly amounts from the Lowest Peak Profile shall be used for one weekday of the month;

6.4.3 The twenty-four (24) hourly amounts from the Weekday Profile shall be used for all the remaining weekdays of the month;

6.4.4 The twenty-four (24) hourly amounts from the Sunday and Holiday Profile shall be used for all Sundays and Holidays occurring in the month; and

6.4.5 The twenty-four (24) hourly amounts from the Saturday Profile shall be used for all Saturdays of the month.

6.4.6 The calculated SSVEC AEPCO Profile Energy for each hour for each month of 2001 is tabulated in Table B-6 in Exhibit B-3 attached hereto.

6.4.7 Schedule A Energy available to SSVEC in each hour shall be the greater of the amount of SSVEC AEPCO Profile Energy of such hour, or the energy associated with SSVEC's share of AEPCO Maximum Base Capacity amount for such hour, as determined in accordance with Section 5 hereof, and as set forth for 2001 in Table B-6 of Exhibit B-3.

6.5 Determining Schedule A Energy and SSVEC AEPCO Profile Capacity Available in Subsequent Years.

The amounts of Schedule A Energy and SSVEC AEPCO Profile Capacity for each month of any subsequent year shall be determined as follows:

6.5.1 Schedule A Energy. In any hour of any month of years subsequent to 2001, Schedule A Energy available to SSVEC shall be the greater of the amount of SSVEC AEPCO Profile Energy applicable in such time periods, or the energy associated with SSVEC's share of AEPCO Maximum Base Capacity. The monthly and hourly amounts of SSVEC AEPCO Profile Energy, plus the corresponding monthly and hourly amounts of SSVEC's share of AEPCO Maximum Base Capacity shall be determined as follows:

6.5.1.1 AC Ratios. The AC Ratios set forth in Tables B-5.1 and B-5.2, shall be used to determine an amount of SSVEC AEPCO Profile Energy and SSVEC AEPCO Profile Capacity.

6.5.1.2 Monthly SSVEC AEPCO Profile Energy. The aggregate amount of SSVEC AEPCO Profile Energy available each month in years subsequent to 2001 shall be obtained by multiplying the aggregate amount of SSVEC AEPCO Profile Energy available for such month in 2001 from Table B-6, by the AC Ratio for such month. Table B-5.2 contains the monthly totals of the SSVEC AEPCO Profile Energy available for each month of each year through the term of the Agreement.

6.5.1.3 Hourly SSVEC AEPCO Profile Energy. The amount of SSVEC AEPCO Profile Energy available for each hour of each month of a year subsequent to 2001 shall be the product of the SSVEC AEPCO Profile Energy amount for such hour in the corresponding month of 2001, multiplied by the AC Ratio for such month.

6.5.1.4 SSVEC Share of AEPCO Maximum Base Capacity. SSVEC's share of Maximum Base Capacity for 2001 is set out in Table B-7 of Exhibit B-3. In order to determine SSVEC's share of AEPCO Maximum Base Capacity for years subsequent to 2001, the amount of SSVEC's share of AEPCO Must-Run Purchase Capacity from Federal Hydro Power Agreements must be determined. AEPCO shall provide SSVEC with a revised Table B-7 to Exhibit B-3 setting forth the amount of SSVEC's share of AEPCO Maximum Base Capacity as soon as practicable after AEPCO receives notice of the amounts of AEPCO Must-Run Purchase Capacity available pursuant to the Federal Hydro Power Agreements.

6.5.2 SSVEC AEPCO Profile Capacity. Each month's amount of SSVEC AEPCO Profile Capacity available in years subsequent to 2001 shall be obtained by multiplying the amount of SSVEC AEPCO Profile Capacity available in the corresponding month of 2001 by the AC Ratio for such month. Table B-5.1 contains the monthly amounts of SSVEC AEPCO Profile Capacity available for each month of each year during the term of the Agreement.

6.5.3 Summary Table for SSVEC AEPCO Profile Capacity and Energy. Attached as Table B-5 is a summary by month and year through the term of the Agreement of the SSVEC AEPCO Profile Capacity and SSVEC AEPCO Profile Energy.

6.6 Identification of Schedule A Energy Within Member Billing Energy. AEPCO shall each month during the term of this Agreement prepare and deliver to SSVEC an hourly tabulation of the amount of energy sold by AEPCO to SSVEC as Member Billing Energy and shall also identify the amount of such energy billed as Schedule A Energy. Such tabulation shall indicate the additional amounts of Schedule A Energy unused and available from SSVEC's share of AEPCO Maximum Base Capacity and the portion of Schedule A Energy unused and available from SSVEC's share of AEPCO Resources other than those included in AEPCO Maximum Base Capacity. Such tabulation shall also show the amount of energy billed and unused and available as Schedule B Energy. Tables B-7 and B-8 of Exhibit B-3 illustrate such tabulations. Any use of Schedule B Energy shall be subject to additional charges as set forth in Section 7 hereof.

6.7 Establishing the AOD SSVEC AEPCO Resource Profile. AEPCO shall provide SSVEC with a SSVEC AEPCO Resource Profile known as the Average Other Day (AOD) Profile for each month through December 31, 2020. The AOD Profile shall compute and illustrate the average hourly component of Schedule A Energy resulting from the four (4) SSVEC AEPCO Resource Profiles containing Peak Hours (AOD

Days), which are Peak Day, Lowest Peak Day, Weekday, and Saturday (AOD Profile Energy). Such AOD Profile shall be developed in accordance with the methodology set out in Exhibit B-4, attached hereto and made a part hereof. The Sunday/Holiday Profile of Exhibit B-2 shall not be affected hereby.

6.7.1 Bounded Period, Scheduling Factor and Scheduling Adjustment. In order to better match its energy pre-schedules to its expected daily load shape, SSVEC shall have the right on a pre-schedule basis to shape its use of AOD Energy using a uniform MWh per hour adjustor derived as set forth below (Scheduling Factor, as defined herein), applied to the AOD Profile Energy in certain hours of AOD Days (Bounded Period, as defined herein), and adding or subtracting a discrete hourly amount of up to five (5) MWh per hour (Scheduling Adjustment), all to be within the certain limits set forth herein and in Section 6.8.2 below.

6.7.1.1 The Bounded Period of a day shall mean the longest uninterrupted period of hours within an AOD Day commencing with the first hour which begins with an amount of Schedule A Energy available under the Peak Day Profile exceeding the amount of Schedule A Energy available from SSVEC's share of AEPCO Maximum Base Capacity, and ending with the last hour which ends with an amount of Schedule A Energy available under the Peak Day Profile exceeding the amount of Schedule A Energy available from SSVEC's share of AEPCO Maximum Base Capacity.

6.7.1.2 The Scheduling Factor for the Bounded Period of any AOD Day in a particular month shall mean the hourly MWhrs up to which the hourly amounts of Schedule A Energy available under such month's AOD Profile may be increased by SSVEC pursuant to the following procedure:

(1) For each hour of the Bounded Period of the AOD Profile for the month, the energy available for that hour in the AOD Profile is subtracted from the energy available for that hour in that month's Peak Day Profile. The difference is then divided by the energy available for that hour under the AOD Profile and the resulting quotient is expressed as a percentage.

(2) The maximum Scheduling Factor for an AOD Day during a month shall be the quotient, rounded down to whole MWhrs, obtained by dividing (i) the product of the lowest percentage for any Bounded Period hour obtained in (1) above, expressed in decimal form, multiplied by the total amount of energy within the Bounded Period of the AOD Profile, expressed in MWhrs, by (ii) the number of hours in the Bounded Period of the AOD Profile.

(3) The maximum Scheduling Factor or any lesser number of whole MWhrs including zero may be chosen by SSVEC as the Scheduling Factor for an AOD Day, and as chosen shall be added to every hour within the Bounded Period of that day.

6.7.1.3 The Scheduling Adjustment is five or fewer whole MWhrs which SSVEC may add to, or subtract from, the total amount of energy available in an hour of the Bounded Period after the Scheduling Factor has been applied to the daily schedule, whether the Scheduling Factor selected was the maximum or any lesser amount including zero. The amounts of Scheduling Adjustment energy added to hours within the Bounded Period of an AOD day and the amount subtracted from hours within the Bounded Period of that day shall net to zero.

6.7.2 <u>Limits on Scheduling Using the AOD Profile</u>. The Peak Day Profile establishes the maximum hourly quantities of Schedule A Energy available to SSVEC in AOD Days of a month. The AOD Profile represents an average over the month of Schedule A Energy available in AOD Days.

6.7.2.1 SSVEC shall limit its pre-schedules of Schedule A Energy in the hours of the Bounded Period of an AOD day to the maximum hourly quantities of the Peak Day Profile for the months in which Bounded Periods can be established, and shall not pre-schedule an amount of Schedule A Energy in any hour of a day that is less than SSVEC's share of Minimum Base Capacity (unless both SSVEC's Total Load that day is less than SSVEC's share of AEPCO Minimum Base Capacity and SSVEC is dispatching only its AC from AEPCO Resources, i.e. not using non-AEPCO Resources).

6.7.2.2 SSVEC shall further limit its use of the Scheduling Factor in AOD Days of a month such that the total monthly pre-scheduled use of Schedule A Energy for AOD Days of that month does not exceed the total Schedule A Energy available in the AOD Days of such month, as such total is set forth in Exhibit B-4. If SSVEC has a separate agreement with AEPCO for delivery of energy in excess of the Schedule A energy for the month, the terms of that agreement will determine the cost of such excess energy. In the event that SSVEC's total pre-schedules of Schedule A Energy in a month exceed its total entitlement to Schedule A Energy in such month without such prior agreement, SSVEC shall pay for the amount of excess pre-scheduled energy at a rate equal to the average energy rate of the highest cost AEPCO Resource dispatched in such month.

6.7.3 <u>Exhibits B-5 & B-6</u>. The methodology described and resulting tables of inputs and outputs required to implement the provisions of this Section 6.7 shall be as set forth in Exhibit B-5 attached hereto and made a part hereof.

The graphical illustration of the AOD Profile reflecting the Exhibit B-5 inputs and outputs, the Bounded Period, the potential use of the Scheduling Factor and the Scheduling Adjustment shall be set forth in Exhibit B-6, attached hereto and made a part hereof.

6.8 Obligations of the Parties for the Period Beyond January 1, 2021. Beginning January 1, 2021, the provisions of Sections 6.1 through 6.7.3 shall no longer be of any force or effect.

6.8.1 Beginning January 1, 2021, SSVEC shall schedule hourly energy available from Members' AC in AEPCO Resources at an amount no less than SSVEC's share of AEPCO Minimum Base Capacity. In the event SSVEC schedules an amount below its share of AEPCO Minimum Base Capacity while supplying any portion of its load from other resources, the provisions of Sections 3.1 and 7.2.2 hereof shall apply.

6.8.2 Except as otherwise applicable pursuant to Section 7.2.2 hereof, the rate chargeable to SSVEC by AEPCO on all energy scheduled by SSVEC from the AC of SSVEC in AEPCO Resources shall be the Schedule A Energy Rate. There shall be no Schedule B Energy for the period beyond January 1, 2021.

6.8.3 If SSVEC schedules capacity and/or energy in excess of the AC of SSVEC in AEPCO Resources (unless under separate agreements arranged and entered into between SSVEC and AEPCO in advance), the provisions of Sections 3.2 and 7.2.3 shall apply.

7. ADDITIONAL CHARGES:

7.1 Ordinary Service.

Unless otherwise provided in this Schedule B, the energy sold by AEPCO to SSVEC pursuant to the Agreement shall be at the rates and Fixed Charge set forth in Exhibit A-1 to Rate Schedule A to the Agreement.

7.2 Additional Charges.

In addition to the charges related to ordinary service, SSVEC shall pay AEPCO the following additional amounts resulting from this Schedule B.

7.2.1 Schedule B Energy. Except as set forth in Section 7.2.3 below, AEPCO shall bill SSVEC monthly for each hour's use by SSVEC of Schedule B Energy in an amount obtained by multiplying Schedule B Energy delivered in each such hour of the billing month by the highest cost energy provided from AEPCO Resources in such hour.

7.2.2 Minimum Base Capacity Violations. In the event that SSVEC has replaced its use of AEPCO Resources with a Member Resource in any hour and fails to take energy from AEPCO sufficient to meet SSVEC's share of AEPCO Minimum Base Capacity, AEPCO shall bill SSVEC the amount obtained by multiplying the lesser of the amount of Member Resource used in such hour, or the amount of SSVEC's deficiency in its share of AEPCO Minimum Base Capacity by the applicable of: (i) the energy rate set forth in Exhibit A-1 of Rate Schedule A; or (ii) to the extent AEPCO sold all or a portion of such energy to others, any positive difference obtained by subtracting the energy rate received by AEPCO related to such sale from the energy rate set forth in Exhibit A-1 of Rate Schedule A (Schedule B Minimum Energy Charge).

7.2.3 Capacity and Energy Above AC. In the event that SSVEC's use of AEPCO Resources exceeds its AC, as set forth in Appendix B to Exhibit A-5 of Rate Schedule A (or as such AC is reduced during Off-Peak Hours), SSVEC shall pay AEPCO each month for such additional capacity and associated energy as follows: (i) an additional capacity charge in an amount equal to the product of AEPCO's All Requirements demand rate, multiplied by the maximum kW demand experienced in the billing period that is in excess of SSVEC's AC (Schedule B Demand Overrun Charge); and (ii) an additional energy charge which shall be an amount equal to the energy rate of the highest cost resource dispatched or purchased by AEPCO in the hour(s) that SSVEC used AEPCO Resources above its AC, multiplied by the amount of such excess energy served in such hour(s) (Schedule B Overrun Energy Charge).

7.2.4 Minimum O&M Charge. In the event SSVEC uses a Member Resource in any month and by such use has caused SSVEC's Member Billing Demand to be less than the SSVEC AEPCO Profile Capacity for that month, AEPCO shall bill SSVEC and SSVEC shall pay an amount equal to the product of the O&M Rate set forth in Exhibit A-1 to Rate Schedule A, multiplied by the difference between the SSVEC AEPCO Profile Capacity and Member Billing Demand. Such difference shall not exceed the amount of Member Resource so used. SSVEC shall advise AEPCO of its hourly use of Member Resources.

7.2.5 Minimum O&M Charge. Beginning January 1, 2021, Section 7.2.4 above shall be replaced as follows: "In the event SSVEC uses a Member Resource in any month and by such use has caused SSVEC's Member Billing Demand to be less than the 90% of the AC of SSVEC in the months of May through September, and 75% of the AC of SSVEC in the months of October through April, AEPCO shall bill SSVEC and SSVEC shall pay an amount equal to the product of the O&M Rate set forth in Exhibit A-1 to Rate Schedule A, multiplied by the difference between the AC of SSVEC resulting from such percentage and Member Billing Demand. Such difference shall not exceed the amount of Member Resource so used. SSVEC shall advise AEPCO of its hourly use of Member Resources."

8. REVISIONS TO TABLES AND EXHIBITS:

From time to time events will occur which will necessitate the revision of the Tables and Exhibits attached to this Schedule B. Such revisions shall only be undertaken in accordance with the following:

8.1 Tables B-1.1 and B-1.2 shall not be modified except by mutual agreement of the Parties.

8.2 Tables B-2, B-3.2, B-4, B-5, B-5.1 and B-5.2 and Exhibit B-3, comprised of Tables B-6, B-7 and B-8, and Exhibits B-4, B-5 and B-6 shall be modified only when the AC of SSVEC is modified pursuant to Sections 3.3, 3.4 or 3.5 of the Agreement. AEPCO shall provide to SSVEC any such modified Table or Exhibit at least fifteen (15) business days before such modification becomes effective.

8.3 Table B-3.1 shall be modified only when notice is received from Western Area Power Administration (Western) changing the allocation of capacity or energy from the Salt Lake City Integrated Projects or the Parker Davis Project to which AEPCO is entitled. AEPCO shall provide any modified Table B-3.1 as soon as practicable after such notice from Western. AEPCO shall maintain a version of Table B-3.1 for operational purposes.

8.4 Table B-3 shall be modified as required by modifications to Tables B-3.1 and B-3.2.

8.5 Whenever a Table or Exhibit is revised such revised Table or Exhibit shall be based upon the same methodology that was used to develop the initial Table or Exhibit. When a Table or Exhibit is revised all other Tables or Exhibits using data derived from such Table or Exhibit shall be revised to conform to any changes in such data.

8.6 Beginning January 1, 2021, Tables B-1, B-1.1, B-1.2, B-2, B-3.2, B-4, B-5, B-5.1, and B-5.2 and Exhibits B-1, B-2, and B-3 (containing Tables B-6, B-7, and B-8) shall be deleted in their entirety.

ATTACHMENT A TO SCHEDULE B

GLOSSARY OF ABBREVIATIONS USED IN TABLES AND EXHIBITS

"AC" - Allocated Capacity

"ACP" - Allocated Capacity Percentage

"AEPCO" - Arizona Electric Power Cooperative, Inc.

"Avg" - Average

"Base" – Power Sales Loads solely from Base load units, Apache Steam Units 2 and 3

"CROD" - Contract Rate of Delivery

"Del'd" - Delivered

"DOW" - Day of Week

"Max" - Maximum

"Max CC" - Maximum Coal Capacity

"MEC" - Mohave Electric Cooperative, Inc.

"Min CC" - Minimum Coal Capacity

"MW" - Megawatts

"MW&E" - Morenci Water & Electric

"MWh" - Megawatt-hours

"Reqs" - Requirements

"SLCA-IP" - Salt Lake City Area Integrated Projects

"SSVEC" - Sulphur Springs Valley Electric Cooperative, Inc.

"w/o" – without

TABLE B-1.1 to Schedule B

Historical Peak Demands of Member and All Requirements Members Coincident with AEPCO Member Peak Demand

SSVEC Peak Demand

1995-1999 MW - Based on Class A Billing Comparison

Month	1995 Peaks	1996 Peaks	1997 Peaks	1998 Peaks	1999 Peaks	1995-99 Average
January	76.8	75.3	79.2	76.8	76.7	77.0
February	63.4	65.3	75.3	82.4	74.5	72.2
March	59.8	65.8	63.2	63.4	66.5	63.7
April	56.6	68.3	60.9	62.1	64.0	62.4
May	64.6	78.8	80.5	71.1	75.0	74.0
June	75.3	80.1	82.5	91.6	96.5	85.2
July	84.1	86.6	85.4	88.4	97.6	88.4
August	83.8	80.8	75.6	89.1	90.5	84.0
September	78.7	64.4	78.6	85.3	85.5	78.5
October	67.3	72.9	73.9	71.5	75.8	72.3
November	59.5	57.1	64.7	66.3	69.9	63.5
December	69.5	76.4	81.0	81.2	79.4	77.5

All Requirements Members' Peak Demand

1995-1999 MW - Based on Class A Billing Comparison

Month	1995 Peaks	1996 Peaks	1997 Peaks	1998 Peaks	1999 Peaks	1995-99 Average
January	57.9	59.7	62.2	64.1	66.2	62.0
February	49.0	52.9	59.9	66.9	70.7	59.9
March	47.7	51.6	56.7	56.3	65.9	55.6
April	43.5	62.5	52.4	56.9	60.6	55.2
May	54.8	69.6	75.3	69.7	86.1	71.1
June	69.8	81.6	85.6	97.5	110.9	89.1
July	84.2	84.0	92.1	105.0	114.5	96.0
August	83.7	83.5	86.0	99.1	105.5	91.6
September	77.6	59.9	85.5	91.1	94.7	81.8
October	57.4	66.5	75.0	74.7	81.6	71.0
November	50.0	46.6	53.1	59.2	63.9	54.6
December	56.5	64.0	64.8	74.6	75.6	67.1

TABLE B-1.2 to Schedule B

Member Historical Peak Demands & Energy From AEPCO Resources

SSVEC Peak Demands

1995-1999 Non-Coincident MW - Based on Actual Hourly Data

Month	1995 Peaks	1996 Peaks	1997 Peaks	1998 Peaks	1999 Peaks	1995-99 Average
January	80.6	76.4	89.2	78.5	83.1	81.6
February	64.9	71.0	76.7	81.3	79.4	74.7
March	61.8	67.8	70.3	77.2	69.8	69.4
April	66.6	69.7	69.1	73.8	73.7	70.6
May	64.4	79.9	80.8	74.5	83.2	76.6
June	76.3	85.1	87.2	94.6	98.7	88.4
July	84.9	87.0	90.9	95.5	98.8	91.4
August	84.9	85.8	86.4	93.6	96.2	89.4
September	68.1	72.5	85.4	87.8	89.3	80.6
October	68.1	76.3	77.8	79.0	82.4	76.7
November	63.3	73.1	68.0	69.6	73.9	69.6
December	74.6	82.1	88.3	87.3	85.9	83.6

SSVEC Energy

MWh - Based on Actual Hourly Data

Month	1995 Energy	1996 Energy	1997 Energy	1998 Energy	1999 Energy	1995-99 Average
January	38,965	38,849	42,164	41,547	42,000	40,705
February	31,729	34,323	36,861	38,943	37,297	35,831
March	34,762	36,979	37,026	39,213	39,616	37,519
April	35,069	36,702	37,631	38,060	39,533	37,399
May	37,059	42,700	41,886	40,519	43,564	41,145
June	39,989	45,009	44,533	45,267	47,729	44,505
July	44,294	46,277	47,997	49,760	47,157	47,097
August	44,225	46,241	45,784	50,038	48,950	47,047
September	34,033	38,351	43,822	45,726	45,454	41,477
October	35,092	39,325	37,823	39,045	41,439	38,545
November	32,818	36,435	36,189	36,845	39,273	36,312
December	38,451	40,819	45,328	43,782	47,121	43,100

TABLE B-2 To Schedule B

Table B-2 - Minimum Coal Capacity Allocation

Year	Month	Average Historical Coincident Peaks: Total Load of All Reqs MW	SSVEC Total Load Average MW	Class A Total Load w/o MEC Average MW	Power Sales Load - MW: ED-2	SRP	Mesa	Power Sales Load MW	AEPCO Del'd Load w/o MEC MW
2004	1	62.0	77.0	139.0	8.0	100.0	15.0	123.0	262.0
2004	2	59.9	72.2	132.1	8.0	100.0	15.0	123.0	255.1
2004	3	55.6	63.7	119.4	8.0	100.0	15.0	123.0	242.4
2004	4	55.2	62.4	117.6	8.0	100.0	15.0	123.0	240.6
2004	5	71.1	74.0	145.1	8.0	100.0	15.0	123.0	268.1
2004	6	89.1	85.2	174.3	8.0	100.0	15.0	123.0	297.3
2004	7	96.0	88.4	184.4	8.0	100.0	15.0	123.0	307.4
2004	8	91.6	84.0	175.5	8.0	100.0	15.0	123.0	298.5
2004	9	81.8	78.5	160.3	8.0	100.0	15.0	123.0	283.3
2004	10	71.0	72.3	143.3	8.0	100.0	15.0	123.0	266.3
2004	11	54.6	63.5	118.0	8.0	100.0	15.0	123.0	241.0
2004	12	67.1	77.5	144.6	8.0	100.0	15.0	123.0	267.6
2005	1	62.0	77.0	139.0	8.0	100.0	15.0	123.0	262.0
2005	2	59.9	72.2	132.1	8.0	100.0	15.0	123.0	255.1
2005	3	55.6	63.7	119.4	8.0	100.0	15.0	123.0	242.4
2005	4	55.2	62.4	117.6	8.0	100.0	15.0	123.0	240.6
2005	5	71.1	74.0	145.1	8.0	100.0	15.0	123.0	268.1
2005	6	89.1	85.2	174.3	8.0	100.0	15.0	123.0	297.3
2005	7	96.0	88.4	184.4	8.0	100.0	15.0	123.0	307.4
2005	8	91.6	84.0	175.5	8.0	100.0	15.0	123.0	298.5
2005	9	81.8	78.5	160.3	8.0	100.0	15.0	123.0	283.3
2005	10	71.0	72.3	143.3	8.0	100.0	15.0	123.0	266.3
2005	11	54.6	63.5	118.0	8.0	100.0	15.0	123.0	241.0
2005	12	67.1	77.5	144.6	8.0	100.0	15.0	123.0	267.6
2006	1	62.0	77.0	139.0	8.0	100.0	15.0	123.0	262.0
2006	2	59.9	72.2	132.1	8.0	100.0	15.0	123.0	255.1
2006	3	55.6	63.7	119.4	8.0	100.0	15.0	123.0	242.4
2006	4	55.2	62.4	117.6	8.0	100.0	15.0	123.0	240.6
2006	5	71.1	74.0	145.1	8.0	100.0	15.0	123.0	268.1
2006	6	89.1	85.2	174.3	8.0	100.0	15.0	123.0	297.3
2006	7	96.0	88.4	184.4	8.0	100.0	15.0	123.0	307.4
2006	8	91.6	84.0	175.5	8.0	100.0	15.0	123.0	298.5
2006	9	81.8	78.5	160.3	8.0	100.0	15.0	123.0	283.3
2006	10	71.0	72.3	143.3	8.0	100.0	15.0	123.0	266.3
2006	11	54.6	63.5	118.0	8.0	100.0	15.0	123.0	241.0
2006	12	67.1	77.5	144.6	8.0	100.0	15.0	123.0	267.6

Year	Month	Power Sales % of AEPCO Del'd Load w/o MEC	Class A Total Load w/o MEC % of AEPCO Del'd Load	Min CC MW	MEC Share of Min CC MW	Remain Min CC MW	Power Sales Load Share of Remaining Min CC	Class A Total Load w/o MEC Share of Remaining Min CC	All Reqs Share of Class A Remaining Min CC 50.6%	SSVEC Share of Class A Remaining Min CC 49.4%
2004	1	47.0%	53.0%	210.0	46.3	163.7	76.8	86.8	43.9	42.9
2004	2	48.2%	51.8%	210.0	45.4	164.6	79.4	85.2	43.1	42.1
2004	3	50.7%	49.3%	210.0	43.7	166.3	84.4	81.9	41.4	40.5
2004	4	51.1%	48.9%	210.0	45.4	164.6	84.2	80.4	40.7	39.7
2004	5	45.9%	54.1%	210.0	49.3	160.7	73.7	87.0	44.0	43.0
2004	6	41.4%	58.6%	210.0	52.5	157.5	65.2	92.4	46.7	45.6
2004	7	40.0%	60.0%	210.0	53.6	156.4	62.6	93.8	47.5	46.3
2004	8	41.2%	58.8%	210.0	53.2	156.8	64.6	92.2	46.7	45.6
2004	9	43.4%	56.6%	210.0	51.7	158.3	68.7	89.6	45.3	44.2
2004	10	46.2%	53.8%	210.0	48.6	161.4	74.6	86.9	44.0	42.9
2004	11	51.0%	49.0%	210.0	43.4	166.6	85.0	81.6	41.3	40.3
2004	12	46.0%	54.0%	210.0	47.1	162.9	74.9	88.1	44.6	43.5
2005	1	47.0%	53.0%	210.0	46.3	163.7	76.8	86.8	43.9	42.9
2005	2	48.2%	51.8%	210.0	45.4	164.6	79.4	85.2	43.1	42.1
2005	3	50.7%	49.3%	210.0	43.7	166.3	84.4	81.9	41.4	40.5
2005	4	51.1%	48.9%	210.0	45.4	164.6	84.2	80.4	40.7	39.7
2005	5	45.9%	54.1%	210.0	49.3	160.7	73.7	87.0	44.0	43.0
2005	6	41.4%	58.6%	210.0	52.5	157.5	65.2	92.4	46.7	45.6
2005	7	40.0%	60.0%	210.0	53.6	156.4	62.6	93.8	47.5	46.3
2005	8	41.2%	58.8%	210.0	53.2	156.8	64.6	92.2	46.7	45.6
2005	9	43.4%	56.6%	210.0	51.7	158.3	68.7	89.6	45.3	44.2
2005	10	46.2%	53.8%	210.0	48.6	161.4	74.6	86.9	44.0	42.9
2005	11	51.0%	49.0%	210.0	43.4	166.6	85.0	81.6	41.3	40.3
2005	12	46.0%	54.0%	210.0	47.1	162.9	74.9	88.1	44.6	43.5
2006	1	47.0%	53.0%	210.0	46.3	163.7	76.8	86.8	43.9	42.9
2006	2	48.2%	51.8%	210.0	45.4	164.6	79.4	85.2	43.1	42.1
2006	3	50.7%	49.3%	210.0	43.7	166.3	84.4	81.9	41.4	40.5
2006	4	51.1%	48.9%	210.0	45.4	164.6	84.2	80.4	40.7	39.7
2006	5	45.9%	54.1%	210.0	49.3	160.7	73.7	87.0	44.0	43.0
2006	6	41.4%	58.6%	210.0	52.5	157.5	65.2	92.4	46.7	45.6
2006	7	40.0%	60.0%	210.0	53.6	156.4	62.6	93.8	47.5	46.3
2006	8	41.2%	58.8%	210.0	53.2	156.8	64.6	92.2	46.7	45.6
2006	9	43.4%	56.6%	210.0	51.7	158.3	68.7	89.6	45.3	44.2
2006	10	46.2%	53.8%	210.0	48.6	161.4	74.6	86.9	44.0	42.9
2006	11	51.0%	49.0%	210.0	43.4	166.6	85.0	81.6	41.3	40.3
2006	12	46.0%	54.0%	210.0	47.1	162.9	74.9	88.1	44.6	43.5

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

Table B-2 - Minimum Coal Capacity Allocation

Year	Month	Average Historical Coincident Peaks: Total Load of All Reqs MW	SSVEC Total Load Average MW	Class A Total Load w/o MEC Average MW	Power Sales Load - MW: ED-2	SRP	Mesa	Power Sales Load MW	AEPCO Del'd Load w/o MEC MW
2007	1	62.0	77.0	139.0	8.0	100.0	15.0	123.0	262.0
2007	2	59.9	72.2	132.1	8.0	100.0	15.0	123.0	255.1
2007	3	55.6	63.7	119.4	8.0	100.0	15.0	123.0	242.4
2007	4	55.2	62.4	117.6	8.0	100.0	15.0	123.0	240.6
2007	5	71.1	74.0	145.1	8.0	100.0	15.0	123.0	268.1
2007	6	89.1	85.2	174.3	8.0	100.0	15.0	123.0	297.3
2007	7	96.0	88.4	184.4	8.0	100.0	15.0	123.0	307.4
2007	8	91.6	84.0	175.5	8.0	100.0	15.0	123.0	298.5
2007	9	81.8	78.5	160.3	8.0	100.0	15.0	123.0	283.3
2007	10	71.0	72.3	143.3	8.0	100.0	15.0	123.0	266.3
2007	11	54.6	63.5	118.0	8.0	100.0	15.0	123.0	241.0
2007	12	67.1	77.5	144.6	8.0	100.0	15.0	123.0	267.6
2008	1	62.0	77.0	139.0	8.0	100.0	15.0	123.0	262.0
2008	2	59.9	72.2	132.1	8.0	100.0	15.0	123.0	255.1
2008	3	55.6	63.7	119.4	8.0	100.0	15.0	123.0	242.4
2008	4	55.2	62.4	117.6	8.0	100.0	15.0	123.0	240.6
2008	5	71.1	74.0	145.1	8.0	100.0	15.0	123.0	268.1
2008	6	89.1	85.2	174.3	8.0	100.0	15.0	123.0	297.3
2008	7	96.0	88.4	184.4	8.0	100.0	15.0	123.0	307.4
2008	8	91.6	84.0	175.5	8.0	100.0	15.0	123.0	298.5
2008	9	81.8	78.5	160.3	8.0	100.0	15.0	123.0	283.3
2008	10	71.0	72.3	143.3	8.0	100.0	15.0	123.0	266.3
2008	11	54.6	63.5	118.0	8.0	100.0	15.0	123.0	241.0
2008	12	67.1	77.5	144.6	8.0	100.0	15.0	123.0	267.6
2009	1	62.0	77.0	139.0	8.0	100.0	0.0	108.0	247.0
2009	2	59.9	72.2	132.1	8.0	100.0	0.0	108.0	240.1
2009	3	55.6	63.7	119.4	8.0	100.0	0.0	108.0	227.4
2009	4	55.2	62.4	117.6	8.0	100.0	0.0	108.0	225.6
2009	5	71.1	74.0	145.1	8.0	100.0	0.0	108.0	253.1
2009	6	89.1	85.2	174.3	8.0	100.0	0.0	108.0	282.3
2009	7	96.0	88.4	184.4	8.0	100.0	0.0	108.0	292.4
2009	8	91.6	84.0	175.5	8.0	100.0	0.0	108.0	283.5
2009	9	81.8	78.5	160.3	8.0	100.0	0.0	108.0	268.3
2009	10	71.0	72.3	143.3	8.0	100.0	0.0	108.0	251.3
2009	11	54.6	63.5	118.0	8.0	100.0	0.0	108.0	226.0
2009	12	67.1	77.5	144.6	8.0	100.0	0.0	108.0	252.6

Year	Month	Power Sales % of AEPCO Del'd Load w/o MEC	Class A Total Load w/o MEC % of AEPCO Del'd Load	Min CC MW	MEC Share of Min CC MW	Remain Min CC MW	Power Sales Load Share of Remaining Min CC	Class A Total Load w/o MEC Share of Remaining Min CC	All Reqs Share of Class A Remaining Min CC 50.6%	SSVEC Share of Class A Remaining Min CC 49.4%
2007	1	47.0%	53.0%	210.0	46.3	163.7	76.8	86.8	43.9	42.9
2007	2	48.2%	51.8%	210.0	45.4	164.6	79.4	85.2	43.1	42.1
2007	3	50.7%	49.3%	210.0	43.7	166.3	84.4	81.9	41.4	40.5
2007	4	51.1%	48.9%	210.0	45.4	164.6	84.2	80.4	40.7	39.7
2007	5	45.9%	54.1%	210.0	49.3	160.7	73.7	87.0	44.0	43.0
2007	6	41.4%	58.6%	210.0	52.5	157.5	65.2	92.4	46.7	45.6
2007	7	40.0%	60.0%	210.0	53.6	156.4	62.6	93.8	47.5	46.3
2007	8	41.2%	58.8%	210.0	53.2	156.8	64.6	92.2	46.7	45.6
2007	9	43.4%	56.6%	210.0	51.7	158.3	68.7	89.6	45.3	44.2
2007	10	46.2%	53.8%	210.0	48.6	161.4	74.6	86.9	44.0	42.9
2007	11	51.0%	49.0%	210.0	43.4	166.6	85.0	81.6	41.3	40.3
2007	12	46.0%	54.0%	210.0	47.1	162.9	74.9	88.1	44.6	43.5
2008	1	47.0%	53.0%	210.0	46.3	163.7	76.8	86.8	43.9	42.9
2008	2	48.2%	51.8%	210.0	45.4	164.6	79.4	85.2	43.1	42.1
2008	3	50.7%	49.3%	210.0	43.7	166.3	84.4	81.9	41.4	40.5
2008	4	51.1%	48.9%	210.0	45.4	164.6	84.2	80.4	40.7	39.7
2008	5	45.9%	54.1%	210.0	49.3	160.7	73.7	87.0	44.0	43.0
2008	6	41.4%	58.6%	210.0	52.5	157.5	65.2	92.4	46.7	45.6
2008	7	40.0%	60.0%	210.0	53.6	156.4	62.6	93.8	47.5	46.3
2008	8	41.2%	58.8%	210.0	53.2	156.8	64.6	92.2	46.7	45.6
2008	9	43.4%	56.6%	210.0	51.7	158.3	68.7	89.6	45.3	44.2
2008	10	46.2%	53.8%	210.0	48.6	161.4	74.6	86.9	44.0	42.9
2008	11	51.0%	49.0%	210.0	43.4	166.6	85.0	81.6	41.3	40.3
2008	12	46.0%	54.0%	210.0	47.1	162.9	74.9	88.1	44.6	43.5
2009	1	43.7%	56.3%	210.0	48.6	161.4	70.6	90.8	46.0	44.9
2009	2	45.0%	55.0%	210.0	47.7	162.3	73.0	89.3	45.2	44.1
2009	3	47.5%	52.5%	210.0	46.0	164.0	77.9	86.1	43.6	42.5
2009	4	47.9%	52.1%	210.0	47.7	162.3	77.7	84.6	42.8	41.8
2009	5	42.7%	57.3%	210.0	51.4	158.6	67.7	90.9	46.0	44.9
2009	6	38.3%	61.7%	210.0	54.5	155.5	59.5	96.0	48.6	47.4
2009	7	36.9%	63.1%	210.0	55.6	154.4	57.0	97.4	49.3	48.1
2009	8	38.1%	61.9%	210.0	55.1	154.9	59.0	95.9	48.5	47.4
2009	9	40.3%	59.7%	210.0	53.8	156.2	62.9	93.3	47.2	46.1
2009	10	43.0%	57.0%	210.0	50.7	159.3	68.4	90.8	46.0	44.9
2009	11	47.8%	52.2%	210.0	45.7	164.3	78.5	85.8	43.4	42.4
2009	12	42.8%	57.2%	210.0	49.3	160.7	68.7	92.0	46.5	45.4

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

Table B-2 - Minimum Coal Capacity Allocation

Year	Month	Average Historical Coincident Peaks: Total Load of All Reqs MW	Average Historical Coincident Peaks: SSVEC Total Load Average MW	Average Historical Coincident Peaks: Class A Total Load w/o MEC Average MW	Power Sales Load - MW: ED-2	Power Sales Load - MW: SRP	Power Sales Load - MW: Mesa	Power Sales Load MW	AEPCO Del'd Load w/o MEC MW
2010	1	62.0	77.0	139.0	8.0	100.0	0.0	108.0	247.0
2010	2	59.9	72.2	132.1	8.0	100.0	0.0	108.0	240.1
2010	3	55.6	63.7	119.4	8.0	100.0	0.0	108.0	227.4
2010	4	55.2	62.4	117.6	8.0	100.0	0.0	108.0	225.6
2010	5	71.1	74.0	145.1	8.0	100.0	0.0	108.0	253.1
2010	6	89.1	85.2	174.3	8.0	100.0	0.0	108.0	282.3
2010	7	96.0	88.4	184.4	8.0	100.0	0.0	108.0	292.4
2010	8	91.6	84.0	175.5	8.0	100.0	0.0	108.0	283.5
2010	9	81.8	78.5	160.3	8.0	100.0	0.0	108.0	268.3
2010	10	71.0	72.3	143.3	8.0	100.0	0.0	108.0	251.3
2010	11	54.6	63.5	118.0	8.0	100.0	0.0	108.0	226.0
2010	12	67.1	77.5	144.6	8.0	100.0	0.0	108.0	252.6
2011	1	62.0	77.0	139.0	8.0	0.0	0.0	8.0	147.0
2011	2	59.9	72.2	132.1	8.0	0.0	0.0	8.0	140.1
2011	3	55.6	63.7	119.4	8.0	0.0	0.0	8.0	127.4
2011	4	55.2	62.4	117.6	8.0	0.0	0.0	8.0	125.6
2011	5	71.1	74.0	145.1	8.0	0.0	0.0	8.0	153.1
2011	6	89.1	85.2	174.3	8.0	0.0	0.0	8.0	182.3
2011	7	96.0	88.4	184.4	8.0	0.0	0.0	8.0	192.4
2011	8	91.6	84.0	175.5	8.0	0.0	0.0	8.0	183.5
2011	9	81.8	78.5	160.3	8.0	0.0	0.0	8.0	168.3
2011	10	71.0	72.3	143.3	8.0	0.0	0.0	8.0	151.3
2011	11	54.6	63.5	118.0	8.0	0.0	0.0	8.0	126.0
2011	12	67.1	77.5	144.6	8.0	0.0	0.0	8.0	152.6
2012	1	62.0	77.0	139.0	8.0	0.0	0.0	8.0	147.0
2012	2	59.9	72.2	132.1	8.0	0.0	0.0	8.0	140.1
2012	3	55.6	63.7	119.4	8.0	0.0	0.0	8.0	127.4
2012	4	55.2	62.4	117.6	8.0	0.0	0.0	8.0	125.6
2012	5	71.1	74.0	145.1	8.0	0.0	0.0	8.0	153.1
2012	6	89.1	85.2	174.3	8.0	0.0	0.0	8.0	182.3
2012	7	96.0	88.4	184.4	8.0	0.0	0.0	8.0	192.4
2012	8	91.6	84.0	175.5	8.0	0.0	0.0	8.0	183.5
2012	9	81.8	78.5	160.3	8.0	0.0	0.0	8.0	168.3
2012	10	71.0	72.3	143.3	8.0	0.0	0.0	8.0	151.3
2012	11	54.6	63.5	118.0	8.0	0.0	0.0	8.0	126.0
2012	12	67.1	77.5	144.6	8.0	0.0	0.0	8.0	152.6

Year	Month	Power Sales % of AEPCO Del'd Load w/o MEC	Class A Total Load w/o MEC % of AEPCO Del'd Load	Min CC MW	MEC Share of Min CC MW	Remain Min CC MW	Power Sales Load Share of Remaining Min CC	Class A Total Load w/o MEC Share of Remaining Min CC	All Reqs Share of Class A Remaining Min CC 50.6%	SSVEC Share of Class A Remaining Min CC 49.4%
2010	1	43.7%	56.3%	210.0	48.6	161.4	70.6	90.8	46.0	44.9
2010	2	45.0%	55.0%	210.0	47.7	162.3	73.0	89.3	45.2	44.1
2010	3	47.5%	52.5%	210.0	46.0	164.0	77.9	86.1	43.6	42.5
2010	4	47.9%	52.1%	210.0	47.7	162.3	77.7	84.6	42.8	41.8
2010	5	42.7%	57.3%	210.0	51.4	158.6	67.7	90.9	46.0	44.9
2010	6	38.3%	61.7%	210.0	54.5	155.5	59.5	96.0	48.6	47.4
2010	7	36.9%	63.1%	210.0	55.6	154.4	57.0	97.4	49.3	48.1
2010	8	38.1%	61.9%	210.0	55.1	154.9	59.0	95.9	48.5	47.4
2010	9	40.3%	59.7%	210.0	53.8	156.2	62.9	93.3	47.2	46.1
2010	10	43.0%	57.0%	210.0	50.7	159.3	68.4	90.8	46.0	44.9
2010	11	47.8%	52.2%	210.0	45.7	164.3	78.5	85.8	43.4	42.4
2010	12	42.8%	57.2%	210.0	49.3	160.7	68.7	92.0	46.5	45.4
2011	1	5.4%	94.6%	210.0	72.3	137.7	7.5	130.2	65.9	64.3
2011	2	5.7%	94.3%	210.0	72.1	137.9	7.9	130.0	65.8	64.2
2011	3	6.3%	93.7%	210.0	71.8	138.2	8.7	129.5	65.5	64.0
2011	4	6.4%	93.6%	210.0	72.1	137.9	8.8	129.1	65.3	63.8
2011	5	5.2%	94.8%	210.0	72.7	137.3	7.2	130.1	65.8	64.3
2011	6	4.4%	95.6%	210.0	73.1	136.9	6.0	130.9	66.2	64.7
2011	7	4.2%	95.8%	210.0	73.3	136.7	5.7	131.0	66.3	64.7
2011	8	4.4%	95.6%	210.0	73.2	136.8	6.0	130.8	66.2	64.6
2011	9	4.8%	95.2%	210.0	73.0	137.0	6.5	130.5	66.0	64.4
2011	10	5.3%	94.7%	210.0	72.6	137.4	7.3	130.1	65.9	64.3
2011	11	6.3%	93.7%	210.0	71.8	138.2	8.8	129.5	65.5	64.0
2011	12	5.2%	94.8%	210.0	72.4	137.6	7.2	130.4	66.0	64.4
2012	1	5.4%	94.6%	210.0	72.3	137.7	7.5	130.2	65.9	64.3
2012	2	5.7%	94.3%	210.0	72.1	137.9	7.9	130.0	65.8	64.2
2012	3	6.3%	93.7%	210.0	71.8	138.2	8.7	129.5	65.5	64.0
2012	4	6.4%	93.6%	210.0	72.1	137.9	8.8	129.1	65.3	63.8
2012	5	5.2%	94.8%	210.0	72.7	137.3	7.2	130.1	65.8	64.3
2012	6	4.4%	95.6%	210.0	73.1	136.9	6.0	130.9	66.2	64.7
2012	7	4.2%	95.8%	210.0	73.3	136.7	5.7	131.0	66.3	64.7
2012	8	4.4%	95.6%	210.0	73.2	136.8	6.0	130.8	66.2	64.6
2012	9	4.8%	95.2%	210.0	73.0	137.0	6.5	130.5	66.0	64.4
2012	10	5.3%	94.7%	210.0	72.6	137.4	7.3	130.1	65.9	64.3
2012	11	6.3%	93.7%	210.0	71.8	138.2	8.8	129.5	65.5	64.0
2012	12	5.2%	94.8%	210.0	72.4	137.6	7.2	130.4	66.0	64.4

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

Table B-2 - Minimum Coal Capacity Allocation

Year	Month	Average Historical Coincident Peaks: Total Load of All Reqs MW	SSVEC Total Load Average MW	Class A Total Load w/o MEC Average MW	Power Sales Load - MW: ED-2	SRP	Mesa	Power Sales Load MW	AEPCO Del'd Load w/o MEC MW
2013	1	62.0	77.0	139.0	0.0	0.0	0.0	0.0	139.0
2013	2	59.9	72.2	132.1	0.0	0.0	0.0	0.0	132.1
2013	3	55.6	63.7	119.4	0.0	0.0	0.0	0.0	119.4
2013	4	55.2	62.4	117.6	0.0	0.0	0.0	0.0	117.6
2013	5	71.1	74.0	145.1	0.0	0.0	0.0	0.0	145.1
2013	6	89.1	85.2	174.3	0.0	0.0	0.0	0.0	174.3
2013	7	96.0	88.4	184.4	0.0	0.0	0.0	0.0	184.4
2013	8	91.6	84.0	175.5	0.0	0.0	0.0	0.0	175.5
2013	9	81.8	78.5	160.3	0.0	0.0	0.0	0.0	160.3
2013	10	71.0	72.3	143.3	0.0	0.0	0.0	0.0	143.3
2013	11	54.6	63.5	118.0	0.0	0.0	0.0	0.0	118.0
2013	12	67.1	77.5	144.6	0.0	0.0	0.0	0.0	144.6
2014	1	62.0	77.0	139.0	0.0	0.0	0.0	0.0	139.0
2014	2	59.9	72.2	132.1	0.0	0.0	0.0	0.0	132.1
2014	3	55.6	63.7	119.4	0.0	0.0	0.0	0.0	119.4
2014	4	55.2	62.4	117.6	0.0	0.0	0.0	0.0	117.6
2014	5	71.1	74.0	145.1	0.0	0.0	0.0	0.0	145.1
2014	6	89.1	85.2	174.3	0.0	0.0	0.0	0.0	174.3
2014	7	96.0	88.4	184.4	0.0	0.0	0.0	0.0	184.4
2014	8	91.6	84.0	175.5	0.0	0.0	0.0	0.0	175.5
2014	9	81.8	78.5	160.3	0.0	0.0	0.0	0.0	160.3
2014	10	71.0	72.3	143.3	0.0	0.0	0.0	0.0	143.3
2014	11	54.6	63.5	118.0	0.0	0.0	0.0	0.0	118.0
2014	12	67.1	77.5	144.6	0.0	0.0	0.0	0.0	144.6
2015	1	62.0	77.0	139.0	0.0	0.0	0.0	0.0	139.0
2015	2	59.9	72.2	132.1	0.0	0.0	0.0	0.0	132.1
2015	3	55.6	63.7	119.4	0.0	0.0	0.0	0.0	119.4
2015	4	55.2	62.4	117.6	0.0	0.0	0.0	0.0	117.6
2015	5	71.1	74.0	145.1	0.0	0.0	0.0	0.0	145.1
2015	6	89.1	85.2	174.3	0.0	0.0	0.0	0.0	174.3
2015	7	96.0	88.4	184.4	0.0	0.0	0.0	0.0	184.4
2015	8	91.6	84.0	175.5	0.0	0.0	0.0	0.0	175.5
2015	9	81.8	78.5	160.3	0.0	0.0	0.0	0.0	160.3
2015	10	71.0	72.3	143.3	0.0	0.0	0.0	0.0	143.3
2015	11	54.6	63.5	118.0	0.0	0.0	0.0	0.0	118.0
2015	12	67.1	77.5	144.6	0.0	0.0	0.0	0.0	144.6

Year	Month	Power Sales % of AEPCO Del'd Load w/o MEC	Class A Total Load w/o MEC % of AEPCO Del'd Load	Min CC MW	MEC Share of Min CC MW	Remain Min CC MW	Power Sales Load Share of Remaining Min CC	Class A Total Load w/o MEC Share of Remaining Min CC	All Reqs Share of Class A Remaining Min CC 50.6%	SSVEC Share of Class A Remaining Min CC 49.4%
2013	1	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2013	2	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2013	3	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2013	4	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2013	5	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2013	6	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2013	7	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2013	8	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2013	9	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2013	10	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2013	11	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2013	12	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2014	1	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2014	2	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2014	3	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2014	4	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2014	5	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2014	6	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2014	7	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2014	8	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2014	9	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2014	10	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2014	11	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2014	12	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2015	1	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2015	2	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2015	3	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2015	4	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2015	5	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2015	6	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2015	7	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2015	8	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2015	9	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2015	10	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2015	11	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2015	12	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

Table B-2 - Minimum Coal Capacity Allocation

Year	Month	Average Historical Coincident Peaks: Total Load of All Reqs MW	SSVEC Total Load Average MW	Class A Total Load w/o MEC Average MW	Power Sales Load - MW: ED-2	SRP	Mesa	Power Sales Load MW	AEPCO Del'd Load w/o MEC MW
2016	1	62.0	77.0	139.0	0.0	0.0	0.0	0.0	139.0
2016	2	59.9	72.2	132.1	0.0	0.0	0.0	0.0	132.1
2016	3	55.6	63.7	119.4	0.0	0.0	0.0	0.0	119.4
2016	4	55.2	62.4	117.6	0.0	0.0	0.0	0.0	117.6
2016	5	71.1	74.0	145.1	0.0	0.0	0.0	0.0	145.1
2016	6	89.1	85.2	174.3	0.0	0.0	0.0	0.0	174.3
2016	7	96.0	88.4	184.4	0.0	0.0	0.0	0.0	184.4
2016	8	91.6	84.0	175.5	0.0	0.0	0.0	0.0	175.5
2016	9	81.8	78.5	160.3	0.0	0.0	0.0	0.0	160.3
2016	10	71.0	72.3	143.3	0.0	0.0	0.0	0.0	143.3
2016	11	54.6	63.5	118.0	0.0	0.0	0.0	0.0	118.0
2016	12	67.1	77.5	144.6	0.0	0.0	0.0	0.0	144.6
2017	1	62.0	77.0	139.0	0.0	0.0	0.0	0.0	139.0
2017	2	59.9	72.2	132.1	0.0	0.0	0.0	0.0	132.1
2017	3	55.6	63.7	119.4	0.0	0.0	0.0	0.0	119.4
2017	4	55.2	62.4	117.6	0.0	0.0	0.0	0.0	117.6
2017	5	71.1	74.0	145.1	0.0	0.0	0.0	0.0	145.1
2017	6	89.1	85.2	174.3	0.0	0.0	0.0	0.0	174.3
2017	7	96.0	88.4	184.4	0.0	0.0	0.0	0.0	184.4
2017	8	91.6	84.0	175.5	0.0	0.0	0.0	0.0	175.5
2017	9	81.8	78.5	160.3	0.0	0.0	0.0	0.0	160.3
2017	10	71.0	72.3	143.3	0.0	0.0	0.0	0.0	143.3
2017	11	54.6	63.5	118.0	0.0	0.0	0.0	0.0	118.0
2017	12	67.1	77.5	144.6	0.0	0.0	0.0	0.0	144.6
2018	1	62.0	77.0	139.0	0.0	0.0	0.0	0.0	139.0
2018	2	59.9	72.2	132.1	0.0	0.0	0.0	0.0	132.1
2018	3	55.6	63.7	119.4	0.0	0.0	0.0	0.0	119.4
2018	4	55.2	62.4	117.6	0.0	0.0	0.0	0.0	117.6
2018	5	71.1	74.0	145.1	0.0	0.0	0.0	0.0	145.1
2018	6	89.1	85.2	174.3	0.0	0.0	0.0	0.0	174.3
2018	7	96.0	88.4	184.4	0.0	0.0	0.0	0.0	184.4
2018	8	91.6	84.0	175.5	0.0	0.0	0.0	0.0	175.5
2018	9	81.8	78.5	160.3	0.0	0.0	0.0	0.0	160.3
2018	10	71.0	72.3	143.3	0.0	0.0	0.0	0.0	143.3
2018	11	54.6	63.5	118.0	0.0	0.0	0.0	0.0	118.0
2018	12	67.1	77.5	144.6	0.0	0.0	0.0	0.0	144.6

Year	Month	Power Sales % of AEPCO Del'd Load w/o MEC	Class A Total Load w/o MEC % of AEPCO Del'd Load	Min CC MW	MEC Share of Min CC MW	Remain Min CC MW	Power Sales Load Share of Remaining Min CC	Class A Total Load w/o MEC Share of Remaining Min CC	All Reqs Share of Class A Remaining Min CC 50.6%	SSVEC Share of Class A Remaining Min CC 49.4%
2016	1	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2016	2	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2016	3	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2016	4	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2016	5	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2016	6	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2016	7	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2016	8	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2016	9	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2016	10	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2016	11	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2016	12	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2017	1	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2017	2	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2017	3	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2017	4	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2017	5	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2017	6	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2017	7	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2017	8	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2017	9	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2017	10	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2017	11	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2017	12	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2018	1	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2018	2	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2018	3	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2018	4	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2018	5	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2018	6	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2018	7	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2018	8	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2018	9	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2018	10	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2018	11	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2018	12	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

Table B-2 - Minimum Coal Capacity Allocation

		Average Historical Coincident Peaks			Power Sales Load - MW				
Year	Month	Total Load of All Reqs MW	SSVEC Total Load Average MW	Class A Total Load w/o MEC Average MW	ED-2	SRP	Mesa	Power Sales Load MW	AEPCO Del'd Load w/o MEC MW
2019	1	62.0	77.0	139.0	0.0	0.0	0.0	0.0	139.0
2019	2	59.9	72.2	132.1	0.0	0.0	0.0	0.0	132.1
2019	3	55.6	63.7	119.4	0.0	0.0	0.0	0.0	119.4
2019	4	55.2	62.4	117.6	0.0	0.0	0.0	0.0	117.6
2019	5	71.1	74.0	145.1	0.0	0.0	0.0	0.0	145.1
2019	6	89.1	85.2	174.3	0.0	0.0	0.0	0.0	174.3
2019	7	96.0	88.4	184.4	0.0	0.0	0.0	0.0	184.4
2019	8	91.6	84.0	175.5	0.0	0.0	0.0	0.0	175.5
2019	9	81.8	78.5	160.3	0.0	0.0	0.0	0.0	160.3
2019	10	71.0	72.3	143.3	0.0	0.0	0.0	0.0	143.3
2019	11	54.6	63.5	118.0	0.0	0.0	0.0	0.0	118.0
2019	12	67.1	77.5	144.6	0.0	0.0	0.0	0.0	144.6
2020	1	62.0	77.0	139.0	0.0	0.0	0.0	0.0	139.0
2020	2	59.9	72.2	132.1	0.0	0.0	0.0	0.0	132.1
2020	3	55.6	63.7	119.4	0.0	0.0	0.0	0.0	119.4
2020	4	55.2	62.4	117.6	0.0	0.0	0.0	0.0	117.6
2020	5	71.1	74.0	145.1	0.0	0.0	0.0	0.0	145.1
2020	6	89.1	85.2	174.3	0.0	0.0	0.0	0.0	174.3
2020	7	96.0	88.4	184.4	0.0	0.0	0.0	0.0	184.4
2020	8	91.6	84.0	175.5	0.0	0.0	0.0	0.0	175.5
2020	9	81.8	78.5	160.3	0.0	0.0	0.0	0.0	160.3
2020	10	71.0	72.3	143.3	0.0	0.0	0.0	0.0	143.3
2020	11	54.6	63.5	118.0	0.0	0.0	0.0	0.0	118.0
2020	12	67.1	77.5	144.6	0.0	0.0	0.0	0.0	144.6

Year	Month	Power Sales % of AEPCO Del'd Load w/o MEC	Class A Total Load w/o MEC % of AEPCO Del'd Load	Min CC MW	MEC Share of Min CC MW	Remain Min CC MW	Power Sales Load Share of Remaining Min CC	Class A Total Load w/o MEC Share of Remaining Min CC	All Reqs Share of Class A Remaining Min CC 50.6%	SSVEC Share of Class A Remaining Min CC 49.4%
2019	1	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2019	2	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2019	3	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2019	4	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2019	5	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2019	6	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2019	7	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2019	8	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2019	9	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2019	10	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2019	11	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2019	12	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2020	1	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2020	2	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2020	3	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2020	4	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2020	5	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2020	6	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2020	7	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2020	8	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2020	9	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2020	10	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2020	11	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6
2020	12	0.0%	100.0%	210.0	75.2	134.8	0.0	134.8	68.2	66.6

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

TABLE B-3 To Schedule B

Must-Run Purchase Capacity Allocations for 2004

Peak Hours						
Month	Year	SLCA-IP Monthly Capacity MW	Parker Davis MW	Class A Share Purchase Agreement MW	Total Must-Run Capacity MW	SSVEC Share Must-Run Capacity MW 0.317
January	2004	1.7	18.4	0.0	20.1	6.4
February	2004	1.7	18.4	0.0	20.1	6.4
March	2004	1.5	23.8	0.0	25.3	8.0
April	2004	7.4	23.8	0.0	31.2	9.9
May	2004	7.5	23.8	0.0	31.3	9.9
June	2004	7.8	23.8	0.0	31.6	10.0
July	2004	8.9	23.8	0.0	32.7	10.4
August	2004	8.3	23.8	0.0	32.1	10.2
September	2004	7.3	23.8	0.0	31.1	9.9
October	2004	1.4	18.4	0.0	19.8	6.3
November	2004	1.4	18.4	0.0	19.8	6.3
December	2004	1.6	18.4	0.0	20.0	6.3

Off Peak Hours						
Month	Year	SLCA-IP Monthly Capacity MW	Parker Davis MW	Class A Share Purchase Agreement MW	Total Must-Run Capacity MW	SSVEC Share Must-Run Capacity MW 0.317
January	2004	0.9	4.9	0.0	5.8	1.8
February	2004	0.9	5.0	0.0	5.9	1.9
March	2004	0.9	9.5	0.0	10.4	3.3
April	2004	4.4	9.4	0.0	13.8	4.4
May	2004	4.4	9.1	0.0	13.4	4.3
June	2004	4.4	9.4	0.0	13.8	4.4
July	2004	4.4	8.6	0.0	13.0	4.1
August	2004	4.4	9.5	0.0	13.9	4.4
September	2004	4.4	8.5	0.0	12.9	4.1
October	2004	0.9	5.2	0.0	6.1	1.9
November	2004	0.9	4.9	0.0	5.8	1.8
December	2004	0.9	4.7	0.0	5.6	1.8

The monthly SLC-IP CROD was reduced by 7% starting in October of 2004.

TABLE B-3.1 To Schedule B

Must-Run Hydro Power Capacity On and Off-Peak Allocation for 2004

Values are MW Unless Noted	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SLCA-IP CROD	2.578	2.578	2.578	12.547	12.547	12.547	12.547	12.547	12.547	2.578	2.578	2.578
Off-Peak % of CROD	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
SLCA-IP Off-Peak Capacity	0.902	0.902	0.902	4.391	4.391	4.391	4.391	4.391	4.391	0.902	0.902	0.902
Parker Contract Energy - MWh	6433	5809	11875	11466	11875	11466	11875	11875	11464	6433	6226	6433
Off-Peak % of Energy	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Parker Off-Peak Energy - MWh	1608	1452	2969	2866	2969	2866	2969	2969	2866	1608	1557	1608
Off-Peak Hours in Month	328	288	312	304	328	304	344	312	336	312	320	344
Parker Off-Peak Capacity	4.903	5.043	9.515	9.429	9.051	9.429	8.630	9.515	8.529	5.155	4.864	4.675
AEPCO Off-Peak Hydro Capacity	**5.806**	**5.945**	**10.418**	**13.821**	**13.443**	**13.821**	**13.022**	**13.907**	**12.921**	**6.057**	**5.767**	**5.578**
Member ACP - %	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Member Off-Peak Hydro Capacity	1.840	1.885	3.302	4.381	4.261	4.381	4.128	4.408	4.096	1.920	1.828	1.768
SLCA-IP Monthly Capacity	1.724	1.667	1.546	7.446	7.488	7.833	8.858	8.349	7.306	1.414	1.428	1.598
Parker - Davis Monthly Capacity	18.4	18.4	23.8	23.8	23.8	23.8	23.8	23.8	23.8	18.4	18.4	18.4
Total On-Peak Capacity	20.124	20.067	25.346	31.246	31.288	31.633	32.658	32.149	31.106	19.814	19.828	19.998
Member ACP - %	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%	31.7%
Member On-Peak Hydro Capacity	6.379	6.361	8.035	9.905	9.918	10.028	10.353	10.191	9.861	6.281	6.285	6.339

TABLE B-3.2 To Schedule B

Must-Run Purchase Agreement Capacity Allocation

Year	Month	1995-99 Avg Historical Coincident Peaks: Total Load of All Reqs Average MW	SSVEC Total Load Average MW	Class A Total Load w/o MEC Average MW	Power Sales Load w/o Base Mesa	Power Sales Load w/o Base MW	AEPCO Del'd Load w/o MEC w/o Base MW	Power Sales % of AEPCO Del'd Load w/o Base	Class A Total Load w/o MEC % of AEPCO Del'd Load w/o Base

Year	Month	Future Purchase Agreement Capacity MW	Power Sales Load Share of Purchase Agreement MW	Class A Total Load w/o MEC Share of Purchase Agreement MW	All Reqs Share of Purchase Agreement MW 50.6%	SSVEC Share of Purchase Agreement MW 49.4%

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

TABLE B-4 To Schedule B

Table B-4 - Maximum Coal Capacity Allocation

Year	Month	Average Historical Coincident Peaks: Total Load of All Reqs MW	SSVEC Total Load Average MW	Class A Total Load w/o MEC Average MW	Power Sales Load Without Share of Max CC - MW: Mesa	Power Sales Load w/o Share of Max CC - MW	AEPCO Del'd Load w/o MEC MW	Power Sales w/o Share of Max CC - % of AEPCO Del'd Load	Class A Total Load w/o MEC % of AEPCO Del'd Load
2004	1	62.0	77.0	139.0	15.0	15.0	154.0	9.7%	90.3%
2004	2	59.9	72.2	132.1	15.0	15.0	147.1	10.2%	89.8%
2004	3	55.6	63.7	119.4	15.0	15.0	134.4	11.2%	88.8%
2004	4	55.2	62.4	117.6	15.0	15.0	132.6	11.3%	88.7%
2004	5	71.1	74.0	145.1	15.0	15.0	160.1	9.4%	90.6%
2004	6	89.1	85.2	174.3	15.0	15.0	189.3	7.9%	92.1%
2004	7	96.0	88.4	184.4	15.0	15.0	199.4	7.5%	92.5%
2004	8	91.6	84.0	175.5	15.0	15.0	190.5	7.9%	92.1%
2004	9	81.8	78.5	160.3	15.0	15.0	175.3	8.6%	91.4%
2004	10	71.0	72.3	143.3	15.0	15.0	158.3	9.5%	90.5%
2004	11	54.6	63.5	118.0	15.0	15.0	133.0	11.3%	88.7%
2004	12	67.1	77.5	144.6	15.0	15.0	159.6	9.4%	90.6%
2005	1	62.0	77.0	139.0	15.0	15.0	154.0	9.7%	90.3%
2005	2	59.9	72.2	132.1	15.0	15.0	147.1	10.2%	89.8%
2005	3	55.6	63.7	119.4	15.0	15.0	134.4	11.2%	88.8%
2005	4	55.2	62.4	117.6	15.0	15.0	132.6	11.3%	88.7%
2005	5	71.1	74.0	145.1	15.0	15.0	160.1	9.4%	90.6%
2005	6	89.1	85.2	174.3	15.0	15.0	189.3	7.9%	92.1%
2005	7	96.0	88.4	184.4	15.0	15.0	199.4	7.5%	92.5%
2005	8	91.6	84.0	175.5	15.0	15.0	190.5	7.9%	92.1%
2005	9	81.8	78.5	160.3	15.0	15.0	175.3	8.6%	91.4%
2005	10	71.0	72.3	143.3	15.0	15.0	158.3	9.5%	90.5%
2005	11	54.6	63.5	118.0	15.0	15.0	133.0	11.3%	88.7%
2005	12	67.1	77.5	144.6	15.0	15.0	159.6	9.4%	90.6%
2006	1	62.0	77.0	139.0	15.0	15.0	154.0	9.7%	90.3%
2006	2	59.9	72.2	132.1	15.0	15.0	147.1	10.2%	89.8%
2006	3	55.6	63.7	119.4	15.0	15.0	134.4	11.2%	88.8%
2006	4	55.2	62.4	117.6	15.0	15.0	132.6	11.3%	88.7%
2006	5	71.1	74.0	145.1	15.0	15.0	160.1	9.4%	90.6%
2006	6	89.1	85.2	174.3	15.0	15.0	189.3	7.9%	92.1%
2006	7	96.0	88.4	184.4	15.0	15.0	199.4	7.5%	92.5%
2006	8	91.6	84.0	175.5	15.0	15.0	190.5	7.9%	92.1%
2006	9	81.8	78.5	160.3	15.0	15.0	175.3	8.6%	91.4%
2006	10	71.0	72.3	143.3	15.0	15.0	158.3	9.5%	90.5%
2006	11	54.6	63.5	118.0	15.0	15.0	133.0	11.3%	88.7%
2006	12	67.1	77.5	144.6	15.0	15.0	159.6	9.4%	90.6%

Year	Month	Max CC MW	Base Power Sales Load Share of Max CC: SRP	ED-2	MEC Share of Max CC	Remaining Max CC MW	Power Sales Load Share of Remain Max CC	Class A Total Load w/o MEC Share of Remain Max CC	All Reqs Share of Class A Remaining Max CC 50.6%	SSVEC Share of Class A Remaining Max CC 49.4%
2004	1	350.0	100.0	8.0	80.5	161.5	15.7	145.7	73.7	72.0
2004	2	350.0	100.0	8.0	80.2	161.8	16.5	145.3	73.5	71.8
2004	3	350.0	100.0	8.0	79.6	162.4	18.1	144.2	73.0	71.3
2004	4	350.0	100.0	8.0	80.2	161.8	18.3	143.5	72.6	70.9
2004	5	350.0	100.0	8.0	81.4	160.6	15.0	145.5	73.6	71.9
2004	6	350.0	100.0	8.0	82.3	159.7	12.7	147.1	74.4	72.6
2004	7	350.0	100.0	8.0	82.6	159.4	12.0	147.4	74.6	72.8
2004	8	350.0	100.0	8.0	82.5	159.5	12.6	147.0	74.4	72.6
2004	9	350.0	100.0	8.0	82.1	159.9	13.7	146.2	74.0	72.2
2004	10	350.0	100.0	8.0	81.2	160.8	15.2	145.6	73.7	71.9
2004	11	350.0	100.0	8.0	79.5	162.5	18.3	144.2	72.9	71.2
2004	12	350.0	100.0	8.0	80.8	161.2	15.2	146.1	73.9	72.2
2005	1	350.0	100.0	8.0	80.5	161.5	15.7	145.7	73.7	72.0
2005	2	350.0	100.0	8.0	80.2	161.8	16.5	145.3	73.5	71.8
2005	3	350.0	100.0	8.0	79.6	162.4	18.1	144.2	73.0	71.3
2005	4	350.0	100.0	8.0	80.2	161.8	18.3	143.5	72.6	70.9
2005	5	350.0	100.0	8.0	81.4	160.6	15.0	145.5	73.6	71.9
2005	6	350.0	100.0	8.0	82.3	159.7	12.7	147.1	74.4	72.6
2005	7	350.0	100.0	8.0	82.6	159.4	12.0	147.4	74.6	72.8
2005	8	350.0	100.0	8.0	82.5	159.5	12.6	147.0	74.4	72.6
2005	9	350.0	100.0	8.0	82.1	159.9	13.7	146.2	74.0	72.2
2005	10	350.0	100.0	8.0	81.2	160.8	15.2	145.6	73.7	71.9
2005	11	350.0	100.0	8.0	79.5	162.5	18.3	144.2	72.9	71.2
2005	12	350.0	100.0	8.0	80.8	161.2	15.2	146.1	73.9	72.2
2006	1	350.0	100.0	8.0	80.5	161.5	15.7	145.7	73.7	72.0
2006	2	350.0	100.0	8.0	80.2	161.8	16.5	145.3	73.5	71.8
2006	3	350.0	100.0	8.0	79.6	162.4	18.1	144.2	73.0	71.3
2006	4	350.0	100.0	8.0	80.2	161.8	18.3	143.5	72.6	70.9
2006	5	350.0	100.0	8.0	81.4	160.6	15.0	145.5	73.6	71.9
2006	6	350.0	100.0	8.0	82.3	159.7	12.7	147.1	74.4	72.6
2006	7	350.0	100.0	8.0	82.6	159.4	12.0	147.4	74.6	72.8
2006	8	350.0	100.0	8.0	82.5	159.5	12.6	147.0	74.4	72.6
2006	9	350.0	100.0	8.0	82.1	159.9	13.7	146.2	74.0	72.2
2006	10	350.0	100.0	8.0	81.2	160.8	15.2	145.6	73.7	71.9
2006	11	350.0	100.0	8.0	79.5	162.5	18.3	144.2	72.9	71.2
2006	12	350.0	100.0	8.0	80.8	161.2	15.2	146.1	73.9	72.2

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

Table B-4 - Maximum Coal Capacity Allocation

Year	Month	Average Historical Coincident Peaks: Total Load of All Reqs MW	Average Historical Coincident Peaks: SSVEC Total Load Average MW	Average Historical Coincident Peaks: Class A Total Load w/o MEC Average MW	Power Sales Load Without Share of Max CC - MW: Mesa	Power Sales Load w/o Share of Max CC - MW	AEPCO Del'd Load w/o MEC MW	Power Sales w/o Share of Max CC - % of AEPCO Del'd Load	Class A Total Load w/o MEC % of AEPCO Del'd Load
2007	1	62.0	77.0	139.0	15.0	15.0	154.0	9.7%	90.3%
2007	2	59.9	72.2	132.1	15.0	15.0	147.1	10.2%	89.8%
2007	3	55.6	63.7	119.4	15.0	15.0	134.4	11.2%	88.8%
2007	4	55.2	62.4	117.6	15.0	15.0	132.6	11.3%	88.7%
2007	5	71.1	74.0	145.1	15.0	15.0	160.1	9.4%	90.6%
2007	6	89.1	85.2	174.3	15.0	15.0	189.3	7.9%	92.1%
2007	7	96.0	88.4	184.4	15.0	15.0	199.4	7.5%	92.5%
2007	8	91.6	84.0	175.5	15.0	15.0	190.5	7.9%	92.1%
2007	9	81.8	78.5	160.3	15.0	15.0	175.3	8.6%	91.4%
2007	10	71.0	72.3	143.3	15.0	15.0	158.3	9.5%	90.5%
2007	11	54.6	63.5	118.0	15.0	15.0	133.0	11.3%	88.7%
2007	12	67.1	77.5	144.6	15.0	15.0	159.6	9.4%	90.6%
2008	1	62.0	77.0	139.0	15.0	15.0	154.0	9.7%	90.3%
2008	2	59.9	72.2	132.1	15.0	15.0	147.1	10.2%	89.8%
2008	3	55.6	63.7	119.4	15.0	15.0	134.4	11.2%	88.8%
2008	4	55.2	62.4	117.6	15.0	15.0	132.6	11.3%	88.7%
2008	5	71.1	74.0	145.1	15.0	15.0	160.1	9.4%	90.6%
2008	6	89.1	85.2	174.3	15.0	15.0	189.3	7.9%	92.1%
2008	7	96.0	88.4	184.4	15.0	15.0	199.4	7.5%	92.5%
2008	8	91.6	84.0	175.5	15.0	15.0	190.5	7.9%	92.1%
2008	9	81.8	78.5	160.3	15.0	15.0	175.3	8.6%	91.4%
2008	10	71.0	72.3	143.3	15.0	15.0	158.3	9.5%	90.5%
2008	11	54.6	63.5	118.0	15.0	15.0	133.0	11.3%	88.7%
2008	12	67.1	77.5	144.6	15.0	15.0	159.6	9.4%	90.6%
2009	1	62.0	77.0	139.0	0.0	0.0	139.0	0.0%	100.0%
2009	2	59.9	72.2	132.1	0.0	0.0	132.1	0.0%	100.0%
2009	3	55.6	63.7	119.4	0.0	0.0	119.4	0.0%	100.0%
2009	4	55.2	62.4	117.6	0.0	0.0	117.6	0.0%	100.0%
2009	5	71.1	74.0	145.1	0.0	0.0	145.1	0.0%	100.0%
2009	6	89.1	85.2	174.3	0.0	0.0	174.3	0.0%	100.0%
2009	7	96.0	88.4	184.4	0.0	0.0	184.4	0.0%	100.0%
2009	8	91.6	84.0	175.5	0.0	0.0	175.5	0.0%	100.0%
2009	9	81.8	78.5	160.3	0.0	0.0	160.3	0.0%	100.0%
2009	10	71.0	72.3	143.3	0.0	0.0	143.3	0.0%	100.0%
2009	11	54.6	63.5	118.0	0.0	0.0	118.0	0.0%	100.0%
2009	12	67.1	77.5	144.6	0.0	0.0	144.6	0.0%	100.0%

Year	Month	Max CC MW	Base Power Sales Load Share of Max CC: SRP	Base Power Sales Load Share of Max CC: ED-2	MEC Share of Max CC	Remaining Max CC MW	Power Sales Load Share of Remain Max CC	Class A Total Load w/o MEC Share of Remain Max CC	All Reqs Share of Class A Remaining Max CC 50.6%	SSVEC Share of Class A Remaining Max CC 49.4%
2007	1	350.0	100.0	8.0	80.5	161.5	15.7	145.7	73.7	72.0
2007	2	350.0	100.0	8.0	80.2	161.8	16.5	145.3	73.5	71.8
2007	3	350.0	100.0	8.0	79.6	162.4	18.1	144.2	73.0	71.3
2007	4	350.0	100.0	8.0	80.2	161.8	18.3	143.5	72.6	70.9
2007	5	350.0	100.0	8.0	81.4	160.6	15.0	145.5	73.6	71.9
2007	6	350.0	100.0	8.0	82.3	159.7	12.7	147.1	74.4	72.6
2007	7	350.0	100.0	8.0	82.6	159.4	12.0	147.4	74.6	72.8
2007	8	350.0	100.0	8.0	82.5	159.5	12.6	147.0	74.4	72.6
2007	9	350.0	100.0	8.0	82.1	159.9	13.7	146.2	74.0	72.2
2007	10	350.0	100.0	8.0	81.2	160.8	15.2	145.6	73.7	71.9
2007	11	350.0	100.0	8.0	79.5	162.5	18.3	144.2	72.9	71.2
2007	12	350.0	100.0	8.0	80.8	161.2	15.2	146.1	73.9	72.2
2008	1	350.0	100.0	8.0	80.5	161.5	15.7	145.7	73.7	72.0
2008	2	350.0	100.0	8.0	80.2	161.8	16.5	145.3	73.5	71.8
2008	3	350.0	100.0	8.0	79.6	162.4	18.1	144.2	73.0	71.3
2008	4	350.0	100.0	8.0	80.2	161.8	18.3	143.5	72.6	70.9
2008	5	350.0	100.0	8.0	81.4	160.6	15.0	145.5	73.6	71.9
2008	6	350.0	100.0	8.0	82.3	159.7	12.7	147.1	74.4	72.6
2008	7	350.0	100.0	8.0	82.6	159.4	12.0	147.4	74.6	72.8
2008	8	350.0	100.0	8.0	82.5	159.5	12.6	147.0	74.4	72.6
2008	9	350.0	100.0	8.0	82.1	159.9	13.7	146.2	74.0	72.2
2008	10	350.0	100.0	8.0	81.2	160.8	15.2	145.6	73.7	71.9
2008	11	350.0	100.0	8.0	79.5	162.5	18.3	144.2	72.9	71.2
2008	12	350.0	100.0	8.0	80.8	161.2	15.2	146.1	73.9	72.2
2009	1	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2009	2	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2009	3	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2009	4	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2009	5	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2009	6	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2009	7	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2009	8	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2009	9	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2009	10	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2009	11	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2009	12	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

Table B-4 - Maximum Coal Capacity Allocation

Year	Month	Average Historical Coincident Peaks: Total Load of All Reqs MW	SSVEC Total Load Average MW	Class A Total Load w/o MEC Average MW	Power Sales Load Without Share of Max CC - MW: Mesa	Power Sales Load w/o Share of Max CC - MW	AEPCO Del'd Load w/o MEC MW	Power Sales w/o Share of Max CC - % of AEPCO Del'd Load	Class A Total Load w/o MEC % of AEPCO Del'd Load
2010	1	62.0	77.0	139.0	0.0	0.0	139.0	0.0%	100.0%
2010	2	59.9	72.2	132.1	0.0	0.0	132.1	0.0%	100.0%
2010	3	55.6	63.7	119.4	0.0	0.0	119.4	0.0%	100.0%
2010	4	55.2	62.4	117.6	0.0	0.0	117.6	0.0%	100.0%
2010	5	71.1	74.0	145.1	0.0	0.0	145.1	0.0%	100.0%
2010	6	89.1	85.2	174.3	0.0	0.0	174.3	0.0%	100.0%
2010	7	96.0	88.4	184.4	0.0	0.0	184.4	0.0%	100.0%
2010	8	91.6	84.0	175.5	0.0	0.0	175.5	0.0%	100.0%
2010	9	81.8	78.5	160.3	0.0	0.0	160.3	0.0%	100.0%
2010	10	71.0	72.3	143.3	0.0	0.0	143.3	0.0%	100.0%
2010	11	54.6	63.5	118.0	0.0	0.0	118.0	0.0%	100.0%
2010	12	67.1	77.5	144.6	0.0	0.0	144.6	0.0%	100.0%
2011	1	62.0	77.0	139.0	0.0	0.0	139.0	0.0%	100.0%
2011	2	59.9	72.2	132.1	0.0	0.0	132.1	0.0%	100.0%
2011	3	55.6	63.7	119.4	0.0	0.0	119.4	0.0%	100.0%
2011	4	55.2	62.4	117.6	0.0	0.0	117.6	0.0%	100.0%
2011	5	71.1	74.0	145.1	0.0	0.0	145.1	0.0%	100.0%
2011	6	89.1	85.2	174.3	0.0	0.0	174.3	0.0%	100.0%
2011	7	96.0	88.4	184.4	0.0	0.0	184.4	0.0%	100.0%
2011	8	91.6	84.0	175.5	0.0	0.0	175.5	0.0%	100.0%
2011	9	81.8	78.5	160.3	0.0	0.0	160.3	0.0%	100.0%
2011	10	71.0	72.3	143.3	0.0	0.0	143.3	0.0%	100.0%
2011	11	54.6	63.5	118.0	0.0	0.0	118.0	0.0%	100.0%
2011	12	67.1	77.5	144.6	0.0	0.0	144.6	0.0%	100.0%
2012	1	62.0	77.0	139.0	0.0	0.0	139.0	0.0%	100.0%
2012	2	59.9	72.2	132.1	0.0	0.0	132.1	0.0%	100.0%
2012	3	55.6	63.7	119.4	0.0	0.0	119.4	0.0%	100.0%
2012	4	55.2	62.4	117.6	0.0	0.0	117.6	0.0%	100.0%
2012	5	71.1	74.0	145.1	0.0	0.0	145.1	0.0%	100.0%
2012	6	89.1	85.2	174.3	0.0	0.0	174.3	0.0%	100.0%
2012	7	96.0	88.4	184.4	0.0	0.0	184.4	0.0%	100.0%
2012	8	91.6	84.0	175.5	0.0	0.0	175.5	0.0%	100.0%
2012	9	81.8	78.5	160.3	0.0	0.0	160.3	0.0%	100.0%
2012	10	71.0	72.3	143.3	0.0	0.0	143.3	0.0%	100.0%
2012	11	54.6	63.5	118.0	0.0	0.0	118.0	0.0%	100.0%
2012	12	67.1	77.5	144.6	0.0	0.0	144.6	0.0%	100.0%

Year	Month	Max CC MW	Base Power Sales Load Share of Max CC: SRP	ED-2	MEC Share of Max CC	Remaining Max CC MW	Power Sales Load Share of Remain Max CC	Class A Total Load w/o MEC Share of Remain Max CC	All Reqs Share of Class A Remaining Max CC 50.6%	SSVEC Share of Class A Remaining Max CC 49.4%
2010	1	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2010	2	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2010	3	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2010	4	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2010	5	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2010	6	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2010	7	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2010	8	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2010	9	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2010	10	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2010	11	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2010	12	350.0	100.0	8.0	86.6	155.4	0.0	155.4	78.6	76.7
2011	1	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2011	2	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2011	3	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2011	4	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2011	5	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2011	6	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2011	7	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2011	8	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2011	9	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2011	10	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2011	11	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2011	12	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2012	1	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2012	2	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2012	3	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2012	4	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2012	5	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2012	6	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2012	7	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2012	8	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2012	9	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2012	10	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2012	11	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5
2012	12	350.0	0.0	8.0	122.4	219.6	0.0	219.6	111.1	108.5

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

Table B-4 - Maximum Coal Capacity Allocation

Year	Month	Average Historical Coincident Peaks: Total Load of All Reqs MW	SSVEC Total Load Average MW	Class A Total Load w/o MEC Average MW	Power Sales Load Without Share of Max CC - MW: Mesa	Power Sales Load w/o Share of Max CC - MW	AEPCO Del'd Load w/o MEC MW	Power Sales w/o Share of Max CC - % of AEPCO Del'd Load	Class A Total Load w/o MEC % of AEPCO Del'd Load
2013	1	62.0	77.0	139.0	0.0	0.0	139.0	0.0%	100.0%
2013	2	59.9	72.2	132.1	0.0	0.0	132.1	0.0%	100.0%
2013	3	55.6	63.7	119.4	0.0	0.0	119.4	0.0%	100.0%
2013	4	55.2	62.4	117.6	0.0	0.0	117.6	0.0%	100.0%
2013	5	71.1	74.0	145.1	0.0	0.0	145.1	0.0%	100.0%
2013	6	89.1	85.2	174.3	0.0	0.0	174.3	0.0%	100.0%
2013	7	96.0	88.4	184.4	0.0	0.0	184.4	0.0%	100.0%
2013	8	91.6	84.0	175.5	0.0	0.0	175.5	0.0%	100.0%
2013	9	81.8	78.5	160.3	0.0	0.0	160.3	0.0%	100.0%
2013	10	71.0	72.3	143.3	0.0	0.0	143.3	0.0%	100.0%
2013	11	54.6	63.5	118.0	0.0	0.0	118.0	0.0%	100.0%
2013	12	67.1	77.5	144.6	0.0	0.0	144.6	0.0%	100.0%
2014	1	62.0	77.0	139.0	0.0	0.0	139.0	0.0%	100.0%
2014	2	59.9	72.2	132.1	0.0	0.0	132.1	0.0%	100.0%
2014	3	55.6	63.7	119.4	0.0	0.0	119.4	0.0%	100.0%
2014	4	55.2	62.4	117.6	0.0	0.0	117.6	0.0%	100.0%
2014	5	71.1	74.0	145.1	0.0	0.0	145.1	0.0%	100.0%
2014	6	89.1	85.2	174.3	0.0	0.0	174.3	0.0%	100.0%
2014	7	96.0	88.4	184.4	0.0	0.0	184.4	0.0%	100.0%
2014	8	91.6	84.0	175.5	0.0	0.0	175.5	0.0%	100.0%
2014	9	81.8	78.5	160.3	0.0	0.0	160.3	0.0%	100.0%
2014	10	71.0	72.3	143.3	0.0	0.0	143.3	0.0%	100.0%
2014	11	54.6	63.5	118.0	0.0	0.0	118.0	0.0%	100.0%
2014	12	67.1	77.5	144.6	0.0	0.0	144.6	0.0%	100.0%
2015	1	62.0	77.0	139.0	0.0	0.0	139.0	0.0%	100.0%
2015	2	59.9	72.2	132.1	0.0	0.0	132.1	0.0%	100.0%
2015	3	55.6	63.7	119.4	0.0	0.0	119.4	0.0%	100.0%
2015	4	55.2	62.4	117.6	0.0	0.0	117.6	0.0%	100.0%
2015	5	71.1	74.0	145.1	0.0	0.0	145.1	0.0%	100.0%
2015	6	89.1	85.2	174.3	0.0	0.0	174.3	0.0%	100.0%
2015	7	96.0	88.4	184.4	0.0	0.0	184.4	0.0%	100.0%
2015	8	91.6	84.0	175.5	0.0	0.0	175.5	0.0%	100.0%
2015	9	81.8	78.5	160.3	0.0	0.0	160.3	0.0%	100.0%
2015	10	71.0	72.3	143.3	0.0	0.0	143.3	0.0%	100.0%
2015	11	54.6	63.5	118.0	0.0	0.0	118.0	0.0%	100.0%
2015	12	67.1	77.5	144.6	0.0	0.0	144.6	0.0%	100.0%

Year	Month	Max CC MW	Base Power Sales Load Share of Max CC: SRP	ED-2	MEC Share of Max CC	Remaining Max CC MW	Power Sales Load Share of Remain Max CC	Class A Total Load w/o MEC Share of Remain Max CC	All Reqs Share of Class A Remaining Max CC 50.6%	SSVEC Share of Class A Remaining Max CC 49.4%
2013	1	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2013	2	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2013	3	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2013	4	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2013	5	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2013	6	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2013	7	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2013	8	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2013	9	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2013	10	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2013	11	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2013	12	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2014	1	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2014	2	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2014	3	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2014	4	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2014	5	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2014	6	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2014	7	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2014	8	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2014	9	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2014	10	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2014	11	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2014	12	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2015	1	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2015	2	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2015	3	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2015	4	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2015	5	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2015	6	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2015	7	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2015	8	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2015	9	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2015	10	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2015	11	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2015	12	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

Table B-4 - Maximum Coal Capacity Allocation

Year	Month	Average Historical Coincident Peaks: Total Load of All Reqs MW	SSVEC Total Load Average MW	Class A Total Load w/o MEC Average MW	Power Sales Load Without Share of Max CC - MW: Mesa	Power Sales Load w/o Share of Max CC - MW	AEPCO Del'd Load w/o MEC MW	Power Sales w/o Share of Max CC - % of AEPCO Del'd Load	Class A Total Load w/o MEC % of AEPCO Del'd Load
2016	1	62.0	77.0	139.0	0.0	0.0	139.0	0.0%	100.0%
2016	2	59.9	72.2	132.1	0.0	0.0	132.1	0.0%	100.0%
2016	3	55.6	63.7	119.4	0.0	0.0	119.4	0.0%	100.0%
2016	4	55.2	62.4	117.6	0.0	0.0	117.6	0.0%	100.0%
2016	5	71.1	74.0	145.1	0.0	0.0	145.1	0.0%	100.0%
2016	6	89.1	85.2	174.3	0.0	0.0	174.3	0.0%	100.0%
2016	7	96.0	88.4	184.4	0.0	0.0	184.4	0.0%	100.0%
2016	8	91.6	84.0	175.5	0.0	0.0	175.5	0.0%	100.0%
2016	9	81.8	78.5	160.3	0.0	0.0	160.3	0.0%	100.0%
2016	10	71.0	72.3	143.3	0.0	0.0	143.3	0.0%	100.0%
2016	11	54.6	63.5	118.0	0.0	0.0	118.0	0.0%	100.0%
2016	12	67.1	77.5	144.6	0.0	0.0	144.6	0.0%	100.0%
2017	1	62.0	77.0	139.0	0.0	0.0	139.0	0.0%	100.0%
2017	2	59.9	72.2	132.1	0.0	0.0	132.1	0.0%	100.0%
2017	3	55.6	63.7	119.4	0.0	0.0	119.4	0.0%	100.0%
2017	4	55.2	62.4	117.6	0.0	0.0	117.6	0.0%	100.0%
2017	5	71.1	74.0	145.1	0.0	0.0	145.1	0.0%	100.0%
2017	6	89.1	85.2	174.3	0.0	0.0	174.3	0.0%	100.0%
2017	7	96.0	88.4	184.4	0.0	0.0	184.4	0.0%	100.0%
2017	8	91.6	84.0	175.5	0.0	0.0	175.5	0.0%	100.0%
2017	9	81.8	78.5	160.3	0.0	0.0	160.3	0.0%	100.0%
2017	10	71.0	72.3	143.3	0.0	0.0	143.3	0.0%	100.0%
2017	11	54.6	63.5	118.0	0.0	0.0	118.0	0.0%	100.0%
2017	12	67.1	77.5	144.6	0.0	0.0	144.6	0.0%	100.0%
2018	1	62.0	77.0	139.0	0.0	0.0	139.0	0.0%	100.0%
2018	2	59.9	72.2	132.1	0.0	0.0	132.1	0.0%	100.0%
2018	3	55.6	63.7	119.4	0.0	0.0	119.4	0.0%	100.0%
2018	4	55.2	62.4	117.6	0.0	0.0	117.6	0.0%	100.0%
2018	5	71.1	74.0	145.1	0.0	0.0	145.1	0.0%	100.0%
2018	6	89.1	85.2	174.3	0.0	0.0	174.3	0.0%	100.0%
2018	7	96.0	88.4	184.4	0.0	0.0	184.4	0.0%	100.0%
2018	8	91.6	84.0	175.5	0.0	0.0	175.5	0.0%	100.0%
2018	9	81.8	78.5	160.3	0.0	0.0	160.3	0.0%	100.0%
2018	10	71.0	72.3	143.3	0.0	0.0	143.3	0.0%	100.0%
2018	11	54.6	63.5	118.0	0.0	0.0	118.0	0.0%	100.0%
2018	12	67.1	77.5	144.6	0.0	0.0	144.6	0.0%	100.0%

Year	Month	Max CC MW	Base Power Sales Load Share of Max CC: SRP	ED-2	MEC Share of Max CC	Remaining Max CC MW	Power Sales Load Share of Remain Max CC	Class A Total Load w/o MEC Share of Remain Max CC	All Reqs Share of Class A Remaining Max CC 50.6%	SSVEC Share of Class A Remaining Max CC 49.4%
2016	1	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2016	2	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2016	3	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2016	4	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2016	5	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2016	6	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2016	7	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2016	8	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2016	9	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2016	10	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2016	11	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2016	12	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2017	1	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2017	2	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2017	3	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2017	4	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2017	5	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2017	6	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2017	7	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2017	8	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2017	9	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2017	10	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2017	11	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2017	12	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2018	1	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2018	2	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2018	3	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2018	4	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2018	5	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2018	6	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2018	7	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2018	8	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2018	9	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2018	10	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2018	11	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2018	12	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

Table B-4 - Maximum Coal Capacity Allocation

Year	Month	Average Historical Coincident Peaks: Total Load of All Reqs MW	Average Historical Coincident Peaks: SSVEC Total Load Average MW	Average Historical Coincident Peaks: Class A Total Load w/o MEC Average MW	Power Sales Load Without Share of Max CC - MW: Mesa	Power Sales Load w/o Share of Max CC - MW	AEPCO Def'd Load w/o MEC MW	Power Sales w/o Share of Max CC - % of AEPCO Def'd Load	Class A Total Load w/o MEC % of AEPCO Def'd Load
2019	1	62.0	77.0	139.0	0.0	0.0	139.0	0.0%	100.0%
2019	2	59.9	72.2	132.1	0.0	0.0	132.1	0.0%	100.0%
2019	3	55.6	63.7	119.4	0.0	0.0	119.4	0.0%	100.0%
2019	4	55.2	62.4	117.6	0.0	0.0	117.6	0.0%	100.0%
2019	5	71.1	74.0	145.1	0.0	0.0	145.1	0.0%	100.0%
2019	6	89.1	85.2	174.3	0.0	0.0	174.3	0.0%	100.0%
2019	7	96.0	88.4	184.4	0.0	0.0	184.4	0.0%	100.0%
2019	8	91.6	84.0	175.5	0.0	0.0	175.5	0.0%	100.0%
2019	9	81.8	78.5	160.3	0.0	0.0	160.3	0.0%	100.0%
2019	10	71.0	72.3	143.3	0.0	0.0	143.3	0.0%	100.0%
2019	11	54.6	63.5	118.0	0.0	0.0	118.0	0.0%	100.0%
2019	12	67.1	77.5	144.6	0.0	0.0	144.6	0.0%	100.0%
2020	1	62.0	77.0	139.0	0.0	0.0	139.0	0.0%	100.0%
2020	2	59.9	72.2	132.1	0.0	0.0	132.1	0.0%	100.0%
2020	3	55.6	63.7	119.4	0.0	0.0	119.4	0.0%	100.0%
2020	4	55.2	62.4	117.6	0.0	0.0	117.6	0.0%	100.0%
2020	5	71.1	74.0	145.1	0.0	0.0	145.1	0.0%	100.0%
2020	6	89.1	85.2	174.3	0.0	0.0	174.3	0.0%	100.0%
2020	7	96.0	88.4	184.4	0.0	0.0	184.4	0.0%	100.0%
2020	8	91.6	84.0	175.5	0.0	0.0	175.5	0.0%	100.0%
2020	9	81.8	78.5	160.3	0.0	0.0	160.3	0.0%	100.0%
2020	10	71.0	72.3	143.3	0.0	0.0	143.3	0.0%	100.0%
2020	11	54.6	63.5	118.0	0.0	0.0	118.0	0.0%	100.0%
2020	12	67.1	77.5	144.6	0.0	0.0	144.6	0.0%	100.0%

Year	Month	Max CC MW	Base Power Sales Load Share of Max CC: SRP	Base Power Sales Load Share of Max CC: ED-2	MEC Share of Max CC	Remaining Max CC MW	Power Sales Load Share of Remain Max CC	Class A Total Load w/o MEC Share of Remain Max CC	All Reqs Share of Class A Remaining Max CC 50.6%	SSVEC Share of Class A Remaining Max CC 49.4%
2019	1	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2019	2	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2019	3	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2019	4	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2019	5	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2019	6	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2019	7	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2019	8	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2019	9	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2019	10	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2019	11	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2019	12	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2020	1	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2020	2	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2020	3	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2020	4	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2020	5	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2020	6	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2020	7	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2020	8	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2020	9	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2020	10	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2020	11	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0
2020	12	350.0	0.0	0.0	125.3	224.7	0.0	224.7	113.7	111.0

Total ACP = 100.0%

MEC ACP = 35.8%

Remaining Class A ACP = 100% - 35.8% = 64.2%

SSVEC ACP = 31.7%

SSVEC Share = 31.7% / 64.2% = 49.4%

Class A Share = 100.0% - 49.4% = 50.6%

TABLE B-5 To Schedule B

Summary of SSVEC AEPCO Profile Capacity and Energy

Monthly Peak Capacity from AC for SSVEC AEPCO Profile Energy from Table B-5.1 - (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2004	118.9	108.5	97.6	98.8	121.1	131.3	122.7	120.3	118.6	101.1	90.9	110.6
2005	119.0	108.6	97.7	98.9	128.1	138.8	129.8	127.3	125.4	100.9	90.8	110.4
2006	118.9	108.4	97.7	98.8	133.4	144.6	135.2	132.5	130.5	100.6	90.7	110.1
2007	118.6	108.1	97.6	98.9	136.9	148.3	138.7	136.0	133.9	100.3	90.4	109.8
2008	118.3	107.9	97.5	98.8	105.6	114.7	107.4	105.4	103.6	99.8	89.9	109.2
2009	118.3	107.8	97.2	98.5	105.6	114.8	107.4	105.4	103.7	100.1	90.1	109.5
2010	118.0	107.6	97.2	98.5	105.4	114.6	107.3	105.3	103.5	99.8	89.8	109.2
2011	147.2	134.2	120.5	122.1	132.5	143.8	134.4	131.7	129.5	125.4	112.3	136.7
2012	147.0	134.0	120.1	121.8	132.2	143.5	134.2	131.6	129.4	125.2	112.1	136.5
2013	149.5	136.3	122.3	124.0	134.2	145.8	136.3	133.6	131.3	127.3	114.0	138.8
2014	149.6	136.4	122.3	124.0	134.0	145.6	136.1	133.5	131.2	127.1	114.0	138.8
2015	149.6	136.4	122.3	124.0	133.9	145.5	136.0	133.4	131.1	126.9	114.0	138.5
2016	149.3	136.2	122.3	124.1	133.7	145.3	135.9	133.3	130.9	126.7	113.9	138.3
2017	149.1	136.0	122.3	124.1	133.5	145.2	135.8	133.2	130.8	126.5	113.7	138.0
2018	148.8	135.7	122.3	124.1	133.4	145.0	135.7	133.1	130.7	126.3	113.4	137.8
2019	148.6	135.5	122.2	124.0	133.2	144.9	135.6	133.0	130.6	126.1	113.2	137.5
2020	148.4	135.3	122.0	123.8	133.1	144.8	135.5	132.9	130.5	125.9	113.0	137.3

Monthly SSVEC AEPCO Profile Energy from Table B-5.2 - (MWh)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2004	60,791	55,818	53,539	52,152	66,415	66,805	63,453	64,487	61,492	50,793	47,399	57,064
2005	60,842	53,943	53,608	52,197	70,258	70,624	67,111	68,203	65,007	50,662	47,352	56,983
2006	60,784	53,884	53,574	52,178	73,115	73,573	69,911	71,013	67,654	50,515	47,312	56,829
2007	60,630	53,734	53,556	52,213	75,037	75,458	71,717	72,871	69,390	50,394	47,175	56,679
2008	60,477	55,504	53,512	52,178	57,906	58,353	55,545	56,463	53,715	50,135	46,903	56,373
2009	60,476	53,583	53,346	52,028	57,896	58,374	55,575	56,499	53,735	50,264	46,994	56,498
2010	60,323	53,440	53,314	52,003	57,773	58,280	55,497	56,431	53,655	50,133	46,841	56,335
2011	75,236	66,704	66,089	64,463	72,628	73,129	69,497	70,582	67,148	62,973	58,602	70,555
2012	75,131	68,967	65,878	64,318	72,459	73,011	69,404	70,504	67,053	62,880	58,457	70,428
2013	76,435	67,749	67,087	65,458	73,590	74,143	70,473	71,588	68,078	63,951	59,495	71,653
2014	76,464	67,765	67,093	65,475	73,491	74,065	70,408	71,528	68,007	63,838	59,484	71,629
2015	76,455	67,783	67,101	65,489	73,394	73,988	70,344	71,472	67,942	63,734	59,482	71,494
2016	76,325	70,084	67,105	65,505	73,304	73,917	70,285	71,418	67,879	63,630	59,405	71,363
2017	76,200	67,554	67,114	65,517	73,214	73,846	70,227	71,367	67,819	63,533	59,291	71,236
2018	76,077	67,439	67,115	65,531	73,130	73,781	70,172	71,318	67,759	63,427	59,163	71,099
2019	75,957	67,338	67,054	65,451	73,047	73,716	70,124	71,274	67,701	63,333	59,052	70,976
2020	75,837	69,625	66,928	65,341	72,962	73,649	70,068	71,221	67,640	63,235	58,938	70,852

TABLE B-5.1 To Schedule B

Monthly Peak Capacity from AC for SSVEC AEPCO Profile Energy

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Table B-1.2 Peaks	**81.6**	**74.7**	**69.4**	**70.6**	**76.6**	**88.4**	**91.4**	**89.4**	**80.6**	**76.7**	**69.6**	**83.6**
2001 Allocated Capacity	**82.6**	**82.0**	**83.2**	**82.7**	**85.2**	**93.0**	**104.7**	**105.7**	**96.3**	**90.0**	**88.7**	**89.9**
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks over AC												
2001 Resource Peak Demand	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
2004 Allocated Capacity	120.4	119.1	117.0	115.7	134.8	138.2	140.5	142.3	141.7	118.6	115.8	118.9
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2004 to 2001 AC	1.45814	1.45277	1.40665	1.39947	1.58216	1.48602	1.34193	1.34626	1.47144	1.31812	1.30585	1.32208
Scaling of Peaks Below AC	118.9	108.5	97.6	98.8	121.1	131.3	122.7	120.3	118.6	101.1	90.9	110.6
Scaling of Peaks above AC												
2004 Resource Peak Demand	118.9	108.5	97.6	98.8	121.1	131.3	122.7	120.3	118.6	101.1	90.9	110.6
2005 Allocated Capacity	120.5	119.2	117.2	115.8	142.6	146.1	148.6	150.5	149.8	118.3	115.7	118.7
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2005 to 2001 AC	1.45938	1.45411	1.40849	1.40069	1.67371	1.57097	1.41929	1.42384	1.55556	1.31471	1.30456	1.32019
Scaling of Peaks Below AC	119.0	108.6	97.7	98.9	128.1	138.8	129.8	127.3	125.4	100.9	90.8	110.4
Scaling of Peaks above AC												
2005 Resource Peak Demand	119.0	108.6	97.7	98.9	128.1	138.8	129.8	127.3	125.4	100.9	90.8	110.4
2006 Allocated Capacity	120.4	119.1	117.1	115.8	148.4	152.2	154.8	156.7	155.9	118.0	115.6	118.4
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2006 to 2001 AC	1.45797	1.45252	1.40759	1.40018	1.74178	1.63656	1.47851	1.48250	1.61890	1.31090	1.30345	1.31664
Scaling of Peaks Below AC	118.9	108.4	97.7	98.8	133.4	144.6	135.2	132.5	130.5	100.6	90.7	110.1
Scaling of Peaks above AC												
2006 Resource Peak Demand	118.9	108.4	97.7	98.8	133.4	144.6	135.2	132.5	130.5	100.6	90.7	110.1
2007 Allocated Capacity	120.1	118.8	117.1	115.9	152.3	156.1	158.8	160.8	159.9	117.7	115.3	118.1
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2007 to 2001 AC	1.45429	1.44850	1.40710	1.40110	1.78756	1.67849	1.51671	1.52129	1.66044	1.30777	1.29969	1.31315
Scaling of Peaks Below AC	118.6	108.1	97.6	98.9	136.9	148.3	138.7	136.0	133.9	100.3	90.4	109.8
Scaling of Peaks above AC												
2007 Resource Peak Demand	118.6	108.1	97.6	98.9	136.9	148.3	138.7	136.0	133.9	100.3	90.4	109.8
2008 Allocated Capacity	119.8	118.5	117.0	115.8	117.5	120.7	123.0	124.6	123.8	117.1	114.6	117.4
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2008 to 2001 AC	1.45062	1.44460	1.40597	1.40018	1.37947	1.29801	1.17470	1.17875	1.28535	1.30105	1.29219	1.30606
Scaling of Peaks Below AC	118.3	107.9	97.5	98.8	105.6	114.7	107.4	105.4	103.6	99.8	89.9	109.2
Scaling of Peaks above AC												
2008 Resource Peak Demand	118.3	107.9	97.5	98.8	105.6	114.7	107.4	105.4	103.6	99.8	89.9	109.2
2009 Allocated Capacity	119.8	118.4	116.6	115.5	117.5	120.8	123.1	124.7	123.8	117.4	114.8	117.7
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2009 to 2001 AC	1.45060	1.44442	1.40160	1.39614	1.37923	1.29848	1.17532	1.17951	1.28582	1.30440	1.29469	1.30896
Scaling of Peaks Below AC	118.3	107.8	97.2	98.5	105.6	114.8	107.4	105.4	103.7	100.1	90.1	109.5
Scaling of Peaks above AC												
2009 Resource Peak Demand	118.3	107.8	97.2	98.5	105.6	114.8	107.4	105.4	103.7	100.1	90.1	109.5
2010 Allocated Capacity	119.5	118.1	116.5	115.4	117.3	120.6	122.9	124.5	123.6	117.1	114.5	117.3
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2010 to 2001 AC	1.44691	1.44055	1.40074	1.39547	1.37630	1.29638	1.17368	1.17809	1.28391	1.30100	1.29048	1.30519
Scaling of Peaks Below AC	118.0	107.6	97.2	98.5	105.4	114.6	107.3	105.3	103.5	99.8	89.8	109.2
Scaling of Peaks above AC												
2010 Resource Peak Demand	118.0	107.6	97.2	98.5	105.4	114.6	107.3	105.3	103.5	99.8	89.8	109.2

Monthly Peak Capacity from AC for SSVEC AEPCO Profile Energy

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Table B-1.2 Peaks	**81.6**	**74.7**	**69.4**	**70.6**	**76.6**	**88.4**	**91.4**	**89.4**	**80.6**	**76.7**	**69.6**	**83.6**
2001 Allocated Capacity	**82.6**	**82.0**	**83.2**	**82.7**	**85.2**	**93.0**	**104.7**	**105.7**	**96.3**	**90.0**	**88.7**	**89.9**
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks over AC												
2001 Resource Peak Demand	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
2011 Allocated Capacity	149.1	147.4	144.5	143.1	147.4	151.3	153.9	155.8	154.7	147.1	143.2	147.0
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2011 to 2001 AC	1.80462	1.79811	1.73641	1.72985	1.73018	1.62669	1.46975	1.47352	1.60677	1.63420	1.61450	1.63464
Scaling of Peaks Below AC	147.2	134.2	120.5	122.1	132.5	143.8	134.4	131.7	129.5	125.4	112.3	136.7
Scaling of Peaks above AC												
2011 Resource Peak Demand	147.2	134.2	120.5	122.1	132.5	143.8	134.4	131.7	129.5	125.4	112.3	136.7
2012 Allocated Capacity	148.9	147.2	144.0	142.7	147.1	151.0	153.7	155.6	154.5	146.9	142.9	146.7
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2012 to 2001 AC	1.80210	1.79501	1.73085	1.72594	1.72614	1.62407	1.46780	1.47189	1.60450	1.63177	1.61050	1.63171
Scaling of Peaks Below AC	147.0	134.0	120.1	121.8	132.2	143.5	134.2	131.6	129.4	125.2	112.1	136.5
Scaling of Peaks above AC												
2012 Resource Peak Demand	147.0	134.0	120.1	121.8	132.2	143.5	134.2	131.6	129.4	125.2	112.1	136.5
2013 Allocated Capacity	151.4	149.8	146.7	145.3	149.4	153.4	156.0	158.0	156.9	149.4	145.4	149.2
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2013 to 2001 AC	1.83339	1.82627	1.76263	1.75655	1.75310	1.64924	1.49040	1.49450	1.62903	1.65959	1.63909	1.66007
Scaling of Peaks Below AC	149.5	136.3	122.3	124.0	134.2	145.8	136.3	133.6	131.3	127.3	114.0	138.8
Scaling of Peaks above AC												
2013 Resource Peak Demand	149.5	136.3	122.3	124.0	134.2	145.8	136.3	133.6	131.3	127.3	114.0	138.8
2014 Allocated Capacity	151.5	149.8	146.7	145.3	149.2	153.2	155.9	157.8	156.7	149.1	145.4	149.2
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2014 to 2001 AC	1.83409	1.82670	1.76278	1.75701	1.75075	1.64752	1.48903	1.49326	1.62735	1.65665	1.63880	1.65954
Scaling of Peaks Below AC	149.6	136.4	122.3	124.0	134.0	145.6	136.1	133.5	131.2	127.1	114.0	138.8
Scaling of Peaks above AC												
2014 Resource Peak Demand	149.6	136.4	122.3	124.0	134.0	145.6	136.1	133.5	131.2	127.1	114.0	138.8
2015 Allocated Capacity	151.5	149.8	146.7	145.3	149.0	153.1	155.8	157.7	156.6	148.9	145.4	148.9
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2015 to 2001 AC	1.83387	1.82719	1.76299	1.75737	1.74844	1.64580	1.48768	1.49209	1.62578	1.65395	1.63875	1.65640
Scaling of Peaks Below AC	149.6	136.4	122.3	124.0	133.9	145.5	136.0	133.4	131.1	126.9	114.0	138.5
Scaling of Peaks above AC												
2015 Resource Peak Demand	149.6	136.4	122.3	124.0	133.9	145.5	136.0	133.4	131.1	126.9	114.0	138.5
2016 Allocated Capacity	151.2	149.6	146.7	145.4	148.8	152.9	155.6	157.6	156.4	148.6	145.2	148.6
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2016 to 2001 AC	1.83075	1.82407	1.76308	1.75780	1.74627	1.64421	1.48643	1.49097	1.62428	1.65125	1.63663	1.65336
Scaling of Peaks Below AC	149.3	136.2	122.3	124.1	133.7	145.3	135.9	133.3	130.9	126.7	113.9	138.3
Scaling of Peaks above AC												
2016 Resource Peak Demand	149.3	136.2	122.3	124.1	133.7	145.3	135.9	133.3	130.9	126.7	113.9	138.3
2017 Allocated Capacity	151.0	149.3	146.7	145.4	148.6	152.8	155.5	157.5	156.3	148.4	144.9	148.4
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2017 to 2001 AC	1.82776	1.82101	1.76332	1.75812	1.74414	1.64264	1.48521	1.48989	1.62283	1.64873	1.63348	1.65041
Scaling of Peaks Below AC	149.1	136.0	122.3	124.1	133.5	145.2	135.8	133.2	130.8	126.5	113.7	138.0
Scaling of Peaks above AC												
2017 Resource Peak Demand	149.1	136.0	122.3	124.1	133.5	145.2	135.8	133.2	130.8	126.5	113.7	138.0

Monthly Peak Capacity from AC for SSVEC AEPCO Profile Energy

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Table B-1.2 Peaks	**81.6**	**74.7**	**69.4**	**70.6**	**76.6**	**88.4**	**91.4**	**89.4**	**80.6**	**76.7**	**69.6**	**83.6**
2001 Allocated Capacity	**82.6**	**82.0**	**83.2**	**82.7**	**85.2**	**93.0**	**104.7**	**105.7**	**96.3**	**90.0**	**88.7**	**89.9**
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks over AC												
2001 Resource Peak Demand	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
2018 Allocated Capacity	150.7	149.1	146.7	145.4	148.4	152.6	155.4	157.4	156.1	148.1	144.6	148.1
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2018 to 2001 AC	1.82481	1.81793	1.76335	1.75850	1.74215	1.64119	1.48405	1.48887	1.62140	1.64598	1.62995	1.64725
Scaling of Peaks Below AC	148.8	135.7	122.3	124.1	133.4	145.0	135.7	133.1	130.7	126.3	113.4	137.8
Scaling of Peaks above AC												
2018 Resource Peak Demand	148.8	135.7	122.3	124.1	133.4	145.0	135.7	133.1	130.7	126.3	113.4	137.8
2019 Allocated Capacity	150.5	148.8	146.6	145.2	148.3	152.5	155.3	157.3	156.0	147.9	144.3	147.8
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2019 to 2001 AC	1.82193	1.81521	1.76175	1.75634	1.74017	1.63975	1.48303	1.48794	1.62001	1.64353	1.62688	1.64438
Scaling of Peaks Below AC	148.6	135.5	122.2	124.0	133.2	144.9	135.6	133.0	130.6	126.1	113.2	137.5
Scaling of Peaks above AC												
2019 Resource Peak Demand	148.6	135.5	122.2	124.0	133.2	144.9	135.6	133.0	130.6	126.1	113.2	137.5
2020 Allocated Capacity	150.3	148.6	146.3	145.0	148.1	152.4	155.1	157.2	155.9	147.7	144.0	147.6
Peaks below AC	81.6	74.7	69.4	70.6	76.6	88.4	91.4	89.4	80.6	76.7	69.6	83.6
Peaks Above AC												
Ratio of 2020 to 2001 AC	1.81903	1.81214	1.75844	1.75339	1.73814	1.63825	1.48184	1.48684	1.61855	1.64099	1.62377	1.64153
Scaling of Peaks Below AC	148.4	135.3	122.0	123.8	133.1	144.8	135.5	132.9	130.5	125.9	113.0	137.3
Scaling of Peaks above AC												
2020 Resource Peak Demand	148.4	135.3	122.0	123.8	133.1	144.8	135.5	132.9	130.5	125.9	113.0	137.3

TABLE B-5.2 To Schedule B

SSVEC AEPCO Profile Energy From Table B-5.1 Ratios

Table B-6 Profile Energy for 2001 - MWh												
	41,691	**37,097**	**38,061**	**37,265**	**41,977**	**44,956**	**47,285**	**47,901**	**41,790**	**38,535**	**36,297**	**43,162**

Ratio Factors From Table B-5.1 By Year

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2004	1.4581	1.4528	1.4067	1.3995	1.5822	1.4860	1.3419	1.3463	1.4714	1.3181	1.3058	1.3221
2005	1.4594	1.4541	1.4085	1.4007	1.6737	1.5710	1.4193	1.4238	1.5556	1.3147	1.3046	1.3202
2006	1.4580	1.4525	1.4076	1.4002	1.7418	1.6366	1.4785	1.4825	1.6189	1.3109	1.3035	1.3166
2007	1.4543	1.4485	1.4071	1.4011	1.7876	1.6785	1.5167	1.5213	1.6604	1.3078	1.2997	1.3131
2008	1.4506	1.4446	1.4060	1.4002	1.3795	1.2980	1.1747	1.1788	1.2854	1.3010	1.2922	1.3061
2009	1.4506	1.4444	1.4016	1.3961	1.3792	1.2985	1.1753	1.1795	1.2858	1.3044	1.2947	1.3090
2010	1.4469	1.4406	1.4007	1.3955	1.3763	1.2964	1.1737	1.1781	1.2839	1.3010	1.2905	1.3052
2011	1.8046	1.7981	1.7364	1.7298	1.7302	1.6267	1.4698	1.4735	1.6068	1.6342	1.6145	1.6346
2012	1.8021	1.7950	1.7308	1.7259	1.7261	1.6241	1.4678	1.4719	1.6045	1.6318	1.6105	1.6317
2013	1.8334	1.8263	1.7626	1.7565	1.7531	1.6492	1.4904	1.4945	1.6290	1.6596	1.6391	1.6601
2014	1.8341	1.8267	1.7628	1.7570	1.7507	1.6475	1.4890	1.4933	1.6273	1.6567	1.6388	1.6595
2015	1.8339	1.8272	1.7630	1.7574	1.7484	1.6458	1.4877	1.4921	1.6258	1.6539	1.6387	1.6564
2016	1.8307	1.8241	1.7631	1.7578	1.7463	1.6442	1.4864	1.4910	1.6243	1.6513	1.6366	1.6534
2017	1.8278	1.8210	1.7633	1.7581	1.7441	1.6426	1.4852	1.4899	1.6228	1.6487	1.6335	1.6504
2018	1.8248	1.8179	1.7633	1.7585	1.7421	1.6412	1.4840	1.4889	1.6214	1.6460	1.6300	1.6473
2019	1.8219	1.8152	1.7618	1.7563	1.7402	1.6398	1.4830	1.4879	1.6200	1.6435	1.6269	1.6444
2020	1.8190	1.8121	1.7584	1.7534	1.7381	1.6383	1.4818	1.4868	1.6185	1.6410	1.6238	1.6415

Monthly SSVEC AEPCO Profile Energy Resulting from Ratio Factors for 2001-2020

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2004 - Note 1	60,791	55,818	53,539	52,152	66,415	66,805	63,453	64,487	61,492	50,793	47,399	57,064
2005	60,842	53,943	53,608	52,197	70,258	70,624	67,111	68,203	65,007	50,662	47,352	56,983
2006	60,784	53,884	53,574	52,178	73,115	73,573	69,911	71,013	67,654	50,515	47,312	56,829
2007	60,630	53,734	53,556	52,213	75,037	75,458	71,717	72,871	69,390	50,394	47,175	56,679
2008 - Note 1	60,477	55,504	53,512	52,178	57,906	58,353	55,545	56,463	53,715	50,135	46,903	56,373
2009	60,476	53,583	53,346	52,028	57,896	58,374	55,575	56,499	53,735	50,264	46,994	56,498
2010	60,323	53,440	53,314	52,003	57,773	58,280	55,497	56,431	53,655	50,133	46,841	56,335
2011	75,236	66,704	66,089	64,463	72,628	73,129	69,497	70,582	67,148	62,973	58,602	70,555
2012 - Note 1	75,131	68,967	65,878	64,318	72,459	73,011	69,404	70,504	67,053	62,880	58,457	70,428
2013	76,435	67,749	67,087	65,458	73,590	74,143	70,473	71,588	68,078	63,951	59,495	71,653
2014	76,464	67,765	67,093	65,475	73,491	74,065	70,408	71,528	68,007	63,838	59,484	71,629
2015	76,455	67,783	67,101	65,489	73,394	73,988	70,344	71,472	67,942	63,734	59,482	71,494
2016 - Note 1	76,325	70,084	67,105	65,505	73,304	73,917	70,285	71,418	67,879	63,630	59,405	71,363
2017	76,200	67,554	67,114	65,517	73,214	73,846	70,227	71,367	67,819	63,533	59,291	71,236
2018	76,077	67,439	67,115	65,531	73,130	73,781	70,172	71,318	67,759	63,427	59,163	71,099
2019	75,957	67,338	67,054	65,451	73,047	73,716	70,124	71,274	67,701	63,333	59,052	70,976
2020 - Note 1	75,837	69,625	66,928	65,341	72,962	73,649	70,068	71,221	67,640	63,235	58,938	70,852

Note 1: The ratio factors were developed based on a non-leap year (2001) data. February leap year values have been adjusted by the fraction of 29 days to 28 days to reflect one more day of energy delivery.

EXHIBIT B-1
AVERAGE DAILY LOAD CURVES

This exhibit will contain only year 2004 data. The remaining data for 2005 through 2020 is contained on a CD.

EXHIBIT B-2
SSVEC AEPCO RESOURCE PROFILES

This exhibit will contain only year 2004 data. The remaining data for 2005 through 2020 is contained on a CD.

EXHIBIT B-3
TABLES B-6, B-7 AND B-8
TO SCHEDULE B

This exhibit will contain only year 2004 data. The remaining data for 2005 through 2020 is contained on a CD.

EXHIBITS B-4, B-5 and B-6
TO SCHEDULE B

This exhibit will contain only year 2004 data. The remaining data for 2005 through 2020 is contained on a CD.

APPENDIX A

DEFINITIONS AS AMENDED AND RESTATED AS OF THE AGREEMENT DATE

1. These Definitions shall have the respective meanings set forth herein for use in the following agreements and their exhibits and schedules (unless the context in which the term is used in a particular agreement clearly requires otherwise):

    1. MEC Partial Requirements Capacity and Energy Agreement;
    2. Resource Integration Agreement;
    3. MEC Transmission Agreement;
    4. Network Service Agreement;
    5. SSVEC Partial Requirements Capacity and Energy Agreement; and
    6. SSVEC Transmission Agreement.

    hereinafter referred to as "Agreements."

2. These Definitions shall not be amended or modified without advance notice, review and approval by all parties to any of the Agreements, and RUS (as hereinafter defined), which remain executory, and after providing to all parties in advance a listing of any such Agreements in which a proposed amended or modified defined term is contained.

3. The following shall be used in interpreting these Definitions and the Agreements:

    3.1 Unless otherwise required by the context in which any term appears:

    (a) Capitalized terms used in any Agreement shall have the meanings specified in this Appendix A or, if used solely within an Agreement, as set forth in such Agreement.

    (b) The singular shall include the plural and the masculine shall include the feminine and neuter.

    (c) References to "Articles," "Sections," "Schedules," "Appendices" or "Exhibits" shall be to articles, sections, schedules, appendices, or exhibits of the Agreement(s) specified, and references to paragraphs shall be to separate paragraphs of the section or subsection in which the reference occurs.

    (d) The words "herein," "hereof", "hereinbelow" and "hereunder" shall refer to an Agreement, specified as a whole and not to any particular section or subsection of such Agreement; the words "include," "includes" or "including" shall mean "including, but not limited to"; and the words "best effort(s)" shall mean a level of effort which, in the exercise of reasonable judgment in the light of facts known at the time a decision is made, can be expected to accomplish the desired result at a reasonable cost, consistent with Prudent Utility Practice (as hereinafter defined).

(e) Except where the context otherwise indicates, the term "day" shall mean a calendar day, and whenever an event is to be performed by a particular date, or a period ends on a particular date, and the date in question falls on a weekend, a legal holiday in the State of Arizona, or a day when the relevant cooperative is not open for business, the event shall be performed, or the period shall end, on the next succeeding business day.

(f) All accounting terms not specifically defined herein or by specified Accounting Requirements (as hereinafter defined) shall be construed in accordance with Generally Accepted Accounting Principles in the United States of America, consistently applied.

3.2 All references herein to the term "cooperative" shall be to AEPCO, TRANSCO, CSP or a Member (as hereinafter defined) cooperative as appropriate from the context in an Agreement.

3.3 All references to a particular entity shall include such entity's successor and permitted assigns.

3.4 All references herein to any agreement, including its schedules, exhibits and appendices, shall be to such agreement as amended, supplemented or modified.

3.5 All references herein to any Law (as hereinafter defined) shall be to such Law as amended, supplemented, modified or replaced.

3.6 The titles of the articles and sections of the Agreements have been inserted as a matter of convenience of reference only and shall not control or affect the meaning or construction of any of the terms or provisions thereof.

3.7 The parties have agreed to the wording of the Agreements, and none of the provisions thereof shall be construed against one party on the ground that any party is the author of such Agreement or any part thereof.

3.8 In any defined term which begins with the word "Member*," the word Member* may be replaced with the name of a Partial Requirements Member. When the name of a Partial Requirements Member is substituted, the definition remains the same but is applicable only to the named Partial Requirements Member. For example, "Member* Transmission Service" shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of Member* to the Member* AEPCO Load. If MEC is substituted, "MEC Transmission Service means Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of MEC to MEC AEPCO Load."

"AC" shall mean Allocated Capacity, as defined hereinbelow.

"ACC" shall mean the Arizona Corporation Commission or any State of Arizona regulatory agency succeeding to its powers and functions.

"ACP" shall mean Allocated Capacity Percentage, as defined hereinbelow.

"Accounting Requirements" shall mean the requirements of any system of accounts prescribed by the RUS as long as RUS is the holder of any obligation of a cooperative; provided, however, that if a cooperative is specifically required by another Governmental Authority to employ the system of accounts prescribed by that Governmental Authority then "Accounting Requirements" means the system of accounts prescribed by that Governmental Authority; provided, further, however, that if RUS is not a holder of any obligation or, if a holder, RUS does not prescribe a system of accounts applicable to the cooperative, and the cooperative is not specifically required by another Governmental Authority to employ that entity's system of accounts, then "Accounting Requirements" means the requirements of Generally Accepted Accounting Principles or another comprehensive basis of accounting applicable to like entities conducting business similar to that of the cooperative. Generally Accepted Accounting Principles refers to a common set of accounting standards and procedures that are either promulgated by an authoritative accounting rulemaking body or accepted as appropriate due to widespread application in the United States.

"Additional AEPCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by AEPCO.

"Additional CSP Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by CSP.

"Additional TRANSCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by TRANSCO.

"Administrator" shall mean the Administrator of RUS or any other federal regulatory agency or department succeeding to the Administrator's power or functions as a lender or mortgagee to a cooperative.

"AEPCO" shall mean Arizona Electric Power Cooperative, Inc., a non-profit generation and transmission cooperative corporation organized under the Laws of the State of Arizona.

"AEPCO Available Resource(s)" shall mean that portion of AEPCO Resources representing operating reserves which can be sold on an interruptible basis and surplus to AEPCO Total Load.

"AEPCO By-law Amendments" shall mean the amendments to the AEPCO By-laws relating to governance, in the form adopted by AEPCO in accordance with the terms of the AEPCO By-laws and the Laws of the State of Arizona.

"AEPCO By-laws" shall mean the By-laws adopted and amended by the Members or Board of Directors of AEPCO in accordance with the Laws of the State of Arizona.

"AEPCO Class A Member" shall mean: (i) any Class A Member which purchases power and energy from AEPCO pursuant to any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement and is listed in Recital B to the Partial Requirements Capacity and Energy Agreement; or (ii) is determined to be a Class A member by the terms of the AEPCO By-laws.

"AEPCO Closing Date Allocation and Attribution" shall mean the allocations and attributions to be made by AEPCO on the Closing Date, as set forth in Section 2.6of the Member Agreement and Section 2.3 of the Restructuring Agreement.

"AEPCO Delivered Load" shall mean the aggregate of the demand requirements and the associated energy requirements of all electric loads served from AEPCO Resources (including distribution losses but not including reserves or transmission losses), and shall consist of:

1. The loads of All Requirements Members served from AEPCO Resources;
2. MEC AEPCO Load;
3. MEC AEPCO Sales;
4. SSVEC AEPCO Load;
5. SSVEC AEPCO Sales;
6. Power Sales Loads; and
7. CSP AEPCO Load;

(as such terms are defined herein).

"AEPCO Employees" shall mean those individuals employed by AEPCO as of the Closing Date.

"AEPCO Load Forecast" shall mean a listing of the demand and associated energy requirements of AEPCO Total Load (by month for the Resource Forecast Period) to be served from AEPCO Resources.

"AEPCO Mortgage" shall mean the Consolidated Mortgage and Security Agreement, dated as of June 14, 1989, by and among AEPCO, as mortgagor, and the Government acting through the Administrator of the RUS, and CFC, as mortgagees, as amended and consolidated, or restated from time to time, which secures the obligations thereunder and creates a lien on substantially all of the real and tangible personal property of AEPCO in favor of such mortgagees, additional substitute mortgagees and other secured parties.

"AEPCO Notes" shall mean written instruments or notes which evidence the obligation of AEPCO for loans that in whole or in part financed the construction of AEPCO's generation and transmission facilities, the payment of which is guaranteed by the Government pursuant to the REAct, and those written instruments or notes of AEPCO outstanding on the Effective Date (with respect to the MEC Partial Requirements Capacity and Energy Agreement) or the Agreement Date (with respect to the SSVEC Partial Requirements Capacity and Energy Agreement) payable to the Government evidencing loans made by the Government, acting by and through the Administrator of RUS, pursuant to the REAct, or evidencing reimbursement obligations of AEPCO to the Government with respect to the Government's guarantee of the payment of certain notes payable to the order of FFB and all amendments, supplements, extensions, and replacements to, of, or for, such notes, and loans made by, or securities issued to, or obligations undertaken to, others, including the Financial

Entities. AEPCO Notes in the future will also include written instruments, which may evidence additional or new loans or advances that AEPCO may obtain to finance the construction or purchase of new facilities, Future Resources or the modification of Existing Resources, as applicable.

"AEPCO Resource" shall mean a Resource owned or purchased from others by AEPCO.

"AEPCO Retained Personnel" shall mean AEPCO management and other personnel designated as such by the chief executive officer of AEPCO.

"AEPCO Secured Obligations" shall mean the AEPCO Notes, loans made by, or securities issued to, or debt obligations entitled to the lien created by the AEPCO Mortgage.

"AEPCO Total Load" shall mean the aggregate of the demand requirements and the associated energy requirements of: (i) AEPCO Delivered Load plus, (ii) losses related thereto from the transmission of power and energy, plus, (iii) applicable only to the demand requirement computation: the greater of (a) applicable installed capacity margin, or (b) operating reserve requirements.

"Agreement Date" shall mean the first day of the month following the date upon which the SSVEC Partial Requirements Capacity and Energy Agreement, the SSVEC Transmission Agreement and the Resource Integration Agreement, as amended to include SSVEC, shall have been executed and delivered by the necessary parties and approved by the RUS and, if required, by the ACC and FERC.

"All Requirements Member" shall mean any Class A Member of AEPCO that has entered into any Wholesale Power Contract with AEPCO which provides for the purchase from AEPCO of all such Member's requirements of electric power, which as of the Effective Date consisted of ANZA, DVEC, GCEC, SSVEC AND TRICO, and which as of the Agreement Date, shall consist of ANZA, DVEC, GCEC and TRICO.

"Allocated Capacity" or "AC" shall mean the amount of capacity of AEPCO Resources from which a Partial Requirements Member is entitled to schedule energy in any month as set forth in that Member* Partial Requirements Capacity and Energy Agreement. The AC for each month for the term of such agreement is set forth in Appendix B to Exhibit A-5 to Rate Schedule A of that Agreement.

"Allocated Capacity Percentage" or "ACP" of a Class A Member shall mean the percentage allocation with respect to an AEPCO Resource, for which, if it is a Partial Requirements Member, such Member is responsible, including the allocation of electric capacity, cost responsibility and revenues, as set forth in its Partial Requirements Capacity and Energy Agreement. Appendix A to Exhibit A-5 to Rate Schedule A sets forth the ACP for each Class A Member with respect to Existing Resources.

"Ancillary Services" shall mean the ancillary services required by FERC to be made available with transmission service in accordance with the FERC pro-forma open access transmission tariff, including; but not limited to scheduling, system control and dispatch service; reactive supply and voltage control from generation sources service; regulation and frequency response service; energy imbalance service; operations reserve-spinning reserve service, and; operating reserve -

supplemental reserve service, all as such terms are further defined by FERC in Order No. 888 and 889 and identified in transmission tariffs and service agreements of TRANSCO.

"Annual Planning Report" shall mean the annual written report and analysis given to AEPCO of a Class A Member's short, intermediate and long-range forecast of load and such other planning data required by the Resource Integration Agreement.

"ANZA" shall mean Anza Electric Cooperative, Inc., a non-profit electric cooperative corporation organized and existing under the Laws of the State of California.

"Applicable Additional Contract" shall mean each additional contract as set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement, which either the Restructuring Agreement or the Member Agreement requires to be executed by each party to the Agreements.

"Assignment for Security" shall mean an assignment, transfer, mortgage or pledge of a party's interest in an Agreement made as security for any obligation secured by any indenture, mortgage, deed, deed of trust, security instrument, or similar lien on its system assets, without limitation on the right of the secured party to further assign such Agreement.

"Authorized Representative" shall mean a representative designated by a party pursuant to the terms of an Agreement and authorized to act for such party in certain matters as set forth in the relevant terms of such Agreement.

"Bonds" shall mean the CFC Guaranteed Solid Waste Disposal Revenue Bonds (Series 1994A) and the CFC Guaranteed Pollution Control Revenue Refunding Bonds (Series 1997C).

"CFC" shall mean the National Rural Utilities Cooperative Finance Corporation, a corporation organized under the Laws of the District of Columbia, or similar successor agency.

"Class A Member" shall mean any entity which is or becomes such a Member of AEPCO, TRANSCO or CSP under the relevant cooperative's by-laws.

"Closing" shall mean the execution and delivery of any and all documents and the tendering, transferring or delivering of all payments required to be made or otherwise necessary or desirable to consummate the transactions contemplated by the Restructuring Agreement and the Member Agreement, including such actions and documents described in the Closing Memorandum as specified in Section 8.1 of both the Restructuring Agreement and the Member Agreement, following satisfaction or waiver, if any, of the conditions for Closing therein.

"Closing Date" shall mean the date on which the Closing occurs.

"Closing Memorandum" shall mean that memorandum agreed to by the parties to the Member Agreement prior to the Pre-Closing which sets forth the consents, assignments, transfers, delivery of other approvals, documents, legal opinions, payments and transaction documents to be furnished by the parties, other conditions for Closing, and events and actions required to effect the Closing.

"Collected Funds" shall mean deposited funds in a banking institution that are immediately available for use without any float restrictions.

"Contract Rate of Interest" shall mean the lesser of: (i) the interest rate equal to the effective "Prime Rate" per annum as specified in the "Money Rates" section of the Wall Street Journal or, (ii) the maximum interest rate permitted by applicable Law in the State of Arizona if any is so stated.

"CSP" shall mean Sierra Southwest Cooperative Services, Inc., a non-profit corporation organized under the generation and transmission cooperative corporation Laws of the State of Arizona.

"CSP AEPCO Load" shall mean the sum of the demand and associated energy requirements, including distribution losses, but not including reserves or transmission losses, of the Member JMP Load of each Class A Member and of those other loads for which CSP purchases capacity and energy from AEPCO as specified in separate sales agreements between AEPCO and CSP.

"CSP Assets" shall mean all capital stock of TSEPP, personal property, authorization to make Retail Sales, intangible assets, employee benefit plans, intellectual property, software licenses, employee or consultant agreements, equipment leases and contracts, licenses, any chose in action, and other agreements related to the performance of the CSP Business identified on Schedule 2 to the Restructuring Agreement.

"CSP Business" shall mean: (i) the business of power sales and retail sales; (ii) the provision of personnel and consulting services to AEPCO, TRANSCO, and others pursuant to contract; and, (iii) the ownership and use of the CSP Assets, including responsibility for CSP Liabilities.

"CSP JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of those loads within a Member's Distribution Service Area served using capacity and energy provided by CSP from CSP Resources pursuant to a Joint Marketing Agreement between a Class A Member and CSP.

"CSP Liabilities" shall mean (i) the CSP liabilities identified on Schedule 2 to the Restructuring Agreement, as such obligations exist as of the Closing Date; and (ii) such other obligations relating to the performance of the CSP Business as CSP, AEPCO and TRANSCO may agree upon from time to time in other agreements; and (iii) any liabilities which CSP assumes in accordance with its by-laws.

"CSP Member" shall mean AEPCO, TRANSCO and the Class A Members of AEPCO on the Closing Date and any Person, which has become and retains membership in CSP in accordance with the CSP By-laws.

"CSP Resource" shall mean a Resource owned or purchased by CSP from third parties.

"Debt Service Coverage Ratio" or "DSC" shall mean the financial ratio determined, based on figures shown on RUS Form 12 for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) depreciation and amortization expense, (b) interest on long-term debt (increased by one-third of the amount, if any, by which long-term leases exceed two percent of total margins and equities less regulatory assets), and (c) net patronage capital or margins and (2) dividing the sum obtained by the total of interest and principal billed under long-term debt and debt service requirements.

"Delivery Point" shall mean the interconnection between the TTS and the transmission, distribution system or load of a Class A Member at which TRANSCO is to deliver capacity or energy pursuant to the Transmission Agreement or the Network Service Agreement.

"Direct Assignment Facilities" shall mean those transmission lines, substation facilities (or components thereof) and firm wheeling purchased by TRANSCO, for the sole use and benefit of a TRANSCO Member or of a particular transmission customer receiving service under the TRANSCO Tariff.

"DVEC" shall mean Duncan Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Economy Purchase(s)" shall mean a wholesale purchase of capacity and/or energy for a term not to exceed one year (including all renewal periods) entered into by AEPCO.

"Economy Sale(s)" shall mean a wholesale sale by AEPCO of capacity and energy from AEPCO Available Resources made for monthly, daily or hourly periods of the next twelve months on a pre-scheduled basis.

"Effective Date" shall mean either (i) August 1, 2001, or (ii) the Closing Date.

"Equity" shall be defined in accordance with Accounting Requirements.

"Existing Resource(s)" shall mean the AEPCO Resource(s) as set forth in Appendix B to Exhibit A-5 to Rate Schedule A.

"Existing Wholesale Power Contract" shall mean the Wholesale Power Contract between AEPCO and a Class A Member, and when used in the plural shall mean such contract and similar contracts between AEPCO and each of the Class A Members pursuant to which, in either case, such Class A Member purchases or purchased all its requirements of electric power from AEPCO prior to its becoming a Partial Requirements Member.

"FERC" shall mean the Federal Energy Regulatory Commission, an agency of the United States Department of Energy, or regulatory agency succeeding to the powers and functions thereof.

"FFB" shall mean the Federal Financing Bank, an instrumentality and wholly owned corporation of the Government or any agency or department of the Government succeeding to the powers and functions thereof.

"Financial Entities" shall mean collectively RUS, CFC, FFB, the trustees and bondholders of the Bonds and other lending institutions or issuers of debt who have made loans to or hold securities or other obligations of a cooperative.

"First Right(s) of Refusal" shall mean reciprocal one-time rights of first refusal to sell capacity and associated energy granted by the purchasing party to the selling party pursuant to Section 10.1 of the Resource Integration Agreement. Certain conditional first rights of refusal provided by CSP to AEPCO as set forth in Section 14 of the Resource Integration Agreement shall not be deemed to form a part of this defined term.

"Force Majeure" shall mean the occurrence or non-occurrence of any act, event or cause beyond the control of a party to an Agreement whereby the party is unable to perform its obligation, other than the obligation to pay money, which act, event or cause by that party's exercise of due diligence could not have reasonably been expected and avoided, or which even with the exercise of due diligence, the party has not been able to overcome or avoid or cause to be avoided. Such act, event or cause shall include, but not be limited to: acts of God; failure or threat of immediate failure of facilities; explosions, flood, drought, earthquake, storm, fire, pestilence, lightning and other natural catastrophes; epidemic; war; riot; civil disturbance or disobedience, strike, or labor disturbance, disputes or unrest of whatever nature; civil disputes or unrest of whatever nature; labor, material or fuel shortage; sabotage; vandalism; restraint by court order or public authority; a failure or threat of failure of any generating or transmission facility, which is likely to cause an outage of electric service to customers served from that party's system (including transmission curtailments by a transmission provider) or to cause such party to experience a rapid decline in system voltage or frequency; and, action or non-action by or inability to obtain the necessary authorizations or approvals from any Governmental Authority (but not including the ACC or RUS), provided however, that no act, event or cause that is the result of the lack of necessary financial resources shall constitute an event of "Force Majeure," nor shall an act, event or cause that is the result of the negligence of the party claiming Force Majeure constitute an event of "Force Majeure."

"Form 12A Balance Sheet" shall mean RUS Form 12a, Section B, Balance Sheet.

"Future Resource" shall mean any (i) new AEPCO Generating Resource, or (ii) any AEPCO Power Purchase Resource with a term of greater than five years; either of which Resource would require the assignment of a new ACP to each Class A Member participating in such Resource and an amendment, or a new Exhibit to Rate Schedule A.

"GCEC" shall mean Graham County Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Generally Accepted Auditing Standards" shall mean a common set of auditing standards and procedures that have been developed over time by several auditing boards, the most current set of standards and procedures of which is the Auditing Standards Board.

"Generating Resource" shall mean an interest in any existing, additional, modified or re-powered generating facility or unit, which may be owned (jointly or individually), leased or otherwise acquired by a party; provided that in connection with any lease of an Existing Resource of AEPCO, such leasehold interest shall not be deemed to be a Future Resource for purposes of a Partial Requirements Capacity and Energy Agreement.

"Generation Business" shall mean with respect to AEPCO: (i) the business of generation of electricity; (ii) operation of the Resource Pool; and, (iii) the use, ownership, rights, obligations and duties associated with the generation assets including its agreements for Power Purchase Resources, Power Sales Resources, Economy Purchases and Economy Sales including, but not limited to, the Existing Wholesale Power Contracts and the Partial Requirements Capacity and Energy Agreement.

"Government" shall mean the federal government of the United States of America.

"Governmental Authority" shall mean any local, state, regional, federal, or national administrative, legal, judicial, or executive governmental agency, commission, department, or other governmental entity having jurisdiction over AEPCO, TRANSCO, CSP, their respective Members, or any of their activities.

"Indebtedness" shall mean:

(1) debt incurred or assumed by a cooperative for borrowed money, or debt incurred for the reimbursement of money advanced under any credit support agreements if in either case categorized as debt according to Accounting Requirements;

(2) lease obligations, if categorized as debt according to Accounting Requirements;

(3) debt incurred or obligations assumed for facilities or power purchases included in a Member's ACP;

(4) debt incurred or obligations issued to finance the amount of a pre-payment; or

(5) debt for any Person (other than debt otherwise treated as Indebtedness hereunder) described in clauses (1), (2), (3) or (4) above which are guaranteed (whether by payment or collection) by the cooperative, provided that none of the following shall constitute Indebtedness:

(A) guarantees of performance or payment by, or any obligations of, any Person under contracts to pay for fuel for the system; and

(B) guarantees of performance by any Person for other than payment of debt incurred or assumed for borrowed money, or any obligation if categorized as debt according to Accounting Requirements, including, without limitation, all debt (other than indebtedness otherwise treated as Indebtedness hereunder) for borrowed money or the acquisition, construction or improvement of property or capitalized lease obligations guaranteed directly or indirectly, in any manner by a cooperative, or in effect guaranteed, directly or indirectly, by such cooperative through an agreement, contingent or otherwise, to assume any such indebtedness or to advance or supply funds for the payment or purchase of any such indebtedness or to purchase property or services primarily for the purpose of enabling the debtor or seller to make payment of such indebtedness, or to assure the owner of the indebtedness against loss, because of such indebtedness or to supply funds to or in any other manner invest in the debtor (including any agreement to pay for property or services irrespective of whether or not such property is delivered or such services are rendered) or otherwise.

"Interest Expense" shall mean an amount constituting interest on long-term Indebtedness (less any interest during construction and allowance for funds used during construction including an interest rate swap collar, floor forward or other hedging agreement, arrangement or security, however denominated,) and other interest expense computed in accordance with Accounting Requirements.

"Joint Marketing Agreement" shall mean an agreement by and between CSP and a Class A Member pertaining to joint competitive retail electric marketing and sales activities, in accordance with applicable Law, within such Member's Distribution Service Area.

"Joint Marketing Plan" shall mean a plan designed by and entered into between CSP and a Class A Member concerning Retail Sales, the form of which is set forth in Exhibit B to the Joint Marketing Agreement.

"Law" shall mean any applicable treaty, statute, code, constitutional provision, ordinance, rule, regulation, order, judgment, decree, decision, injunction, process or any similar form of legally binding decision or directive issued by any Governmental Authority including permits and regulatory approvals and any applicable common law.

"Legal Requirement" shall mean any obligation of AEPCO or TRANSCO under Law.

"Load Forecast" shall mean the projections of monthly coincident peak kilowatt and total monthly kilowatt-hour loads of a party to an Agreement.

"MEC" shall mean Mohave Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Member*" shall mean a Partial Requirement Member of AEPCO.

"Member* AEPCO Load" shall have the meaning set forth in Section 1 of the Member* Partial Requirements Capacity and Energy Agreement.

"Member* AEPCO Sales" shall have the meaning set forth in Section 1 of the Member* Partial Requirements Capacity and Energy Agreement.

"Member* External Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located external to the Member's Distribution Service Area of Member* (and not served from line extensions therefrom) for which Member* sells capacity and energy from Member* Resources. The demand and energy requirements of Member* External Load are not included in Member* Metered kW and Member* Metered kWh, respectively.

"Member* Internal Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within the Member's Distribution Service Area of Member* (or served from line extensions therefrom) for which Member* sells capacity and energy from Member* Resources. The demand and energy requirements of Member* Internal Load are included in Member* Metered kW and Member* Metered kWh, respectively.

"Member* Metered kW" shall have the meaning set forth in Section 1 of the Member* Partial Requirements Capacity and Energy Agreement.

“Member* Metered kWh” shall have the meaning set forth in Section 1 of the Member* Partial Requirements Capacity and Energy Agreement.

“Member* Partial Requirements Capacity and Energy Agreement” shall mean the Partial Requirements Capacity and Energy Agreement, by and between AEPCO and Member*.

"Member* Resource(s)" shall mean a Resource of a Partial Requirements Member of AEPCO; Member Resource does not include the capacity and energy purchased from AEPCO under the Partial Requirements Capacity and Energy Agreement, or purchased by AEPCO under separate contract.

“Member* Transmission Agreement” shall mean the Transmission Agreement in the form attached as Exhibit B-2 to the Member Agreement, by and between TRANSCO and Member* for the purposes of Member* Transmission Service.

“Member* Transmission Service” shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of Member* to Member* AEPCO Load.

“Member* Wheeling Load” shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within Member’s Distribution Service Area of Member* (or served from line extensions therefrom), which are supplied by capacity and energy from third parties (and not from Member Resources or the AC of Member*) and for which Member* provides delivery services over its distribution system. The demand and energy requirements of Member* Wheeling Load are included within Member* Metered kW and Member* Metered kWh, respectively.

“Member” shall mean a member of AEPCO, a CSP Member or a TRANSCO Member, as applicable.

“Member Agreement” shall mean the Member Agreement as executed and delivered by and among the Class A Members, AEPCO, TRANSCO and CSP, dated July 2, 2001.

“Member’s Distribution Service Area” shall mean the geographical electric service territory of a Class A Member as certificated by the ACC, the California Public Utility Commission or the New Mexico Public Utility Commission, as applicable, to supply distribution service as well as all other territory so served by such Class A Member pursuant to applicable Law, or any inter-utility border agreement.

“Member JMP Load” shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses of loads located within a Member’s Distribution Service Area served using capacity and energy provided by CSP as a result of a Joint Marketing Agreement between CSP and a Class A Member, for which CSP purchases capacity and energy from AEPCO.

“Member Transaction” shall mean: (i) the consolidation or merger by the Partial Requirements Member with any other Person; (ii) the reorganization or change of the form of the Partial Requirements Member’s business organization from an electric cooperative non-profit membership-owned corporation; or, (iii) the sale, transfer, lease, or other disposal of all or substantially all the Partial Requirements Member's assets to any Person (or any effort or agreement therefor), whether accomplished in a single transaction or contemplated through a series of transactions as set forth in Section 12 of the Partial Requirements Capacity and Energy Agreement and the Transmission Agreement.

"Minor Resource Modification" shall mean an addition, improvement, repair or modification to an AEPCO Generating Resource or the modification or extension of an AEPCO Power Purchase Resource undertaken by AEPCO in its sole discretion, which will not: (i) increase of greater than ten percent the capacity of the AEPCO Resource being modified; (ii) result in an increase of greater than five percent in AEPCO's Revenue Requirement From AEPCO's Class A Members upon the operation of such addition, improvement, repair and modification or extension, as the case may be; or, (iii) extend the term of any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement.

"Must-Pool Resources" shall mean AEPCO Resources and those Resources of CSP and the Partial Requirements Member, which are required to be included in the Resource Pool.

"Native Load" shall mean: (i) for AEPCO, the electric load of wholesale power customers of AEPCO on whose behalf AEPCO, by Law, tariff or contract, has undertaken an obligation to construct, or otherwise obtain, reliably operate and provide AEPCO Resources (including Purchase Power Resources of AEPCO) to meet the electric requirements of such customers and shall include, but not be limited to, AEPCO Delivered Load, (ii) for TRANSCO, "Native Load" shall mean the electric loads of the TTS customers on whose behalf TRANSCO, by Law, tariff or contract (including as TTS successor to AEPCO) has undertaken an obligation to construct and operate the TTS and shall include, but not be limited to, AEPCO Delivered Load, and (iii) for a Member, "Native Load" shall mean the electric load of the customers of a Member to whom such Member sells power and/or energy and on whose behalf the Member, by Law, tariff, or contract, has undertaken an obligation to construct, or otherwise obtain, and reliably operate the Member's system to meet the power supply requirements of such customers.

"Net Utility Plant" shall mean total utility plant less accumulated depreciation as computed consistent with Accounting Requirements.

"Network Integration Transmission Service" shall be described in Part III of the TRANSCO Tariff.

"Network Service Agreement" shall mean the Network Service Agreement by and between TRANSCO, AEPCO and the All Requirements Members, substantially in the form attached as Exhibit B-1 to the Member Agreement.

"Non-Generation Assets" shall mean, as determined in accordance with Accounting Requirements, all assets of AEPCO of every kind, description, and location which shall be acquired by TRANSCO from AEPCO, as of the Closing Date, which are set forth in Schedule 1 to the Restructuring Agreement.

"Non-Pool Loads" shall mean those loads of a Partial Requirements Member or CSP or applicable portions of such loads which are not included in Pooled Loads.

“Non-Pool Resource” means any Resource obtained by a Partial Requirements Member or CSP and which is not included in the Resource Pool.

“O&M” shall mean the general accounting term used to describe activities and expenses involved with the use, operation, maintenance and repair of a cooperative's plant and facilities including expenses associated with activities intended to prevent or remedy an impending or actual breakdown of those facilities. The term O&M does not include the enlargement or improvement of the property owned or leased and operated by a cooperative nor does it include the replacement of retirement units.

“Off-Peak Hours” shall mean those hours defined by the Western Systems Coordinating Council to represent off-peak load periods, which for each day consist of the eight hours of the hour ending at 11:00 p.m. through hour ending at 6:00 a.m., Mountain Standard Time, and the remaining hours of each Sunday and of each of six holidays (New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day).

“Operating Committee” shall mean the standing committee(s) established in the Partial Requirements Capacity and Energy Agreement and assigned by the parties thereto to deal on a prompt and orderly basis with certain technical and operating issues that may arise in connection with system development or operations.

“Optional Pool Resources” shall mean those Resources which a party may commit to the Resource Pool.

“Order No. 888” shall mean that certain FERC order Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. para. 31,036 (1996), order on reh’g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. para. 31,048 (1997), order on reh’g, Order No. 888-B, 81 FERC para. 61,248 (1997), order on reh’g, Order No. 888-C, 82 FERC para. 61,046 (1998).

“Order No. 889” shall mean that certain FERC order Open Access Same-Time Information System and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (1996), FERC Stats. & Regs. para. 31,035 (1996), order on reh’g, Order No. 889-A, 62 Fed. Reg. 12,484 (1997), FERC Stats. & Regs. para. 31,049 (1997), order on reh’g, Order No. 889-B, 81 FERC 61,253 (1997).

"Partial Requirements Member" shall mean MEC, SSVEC or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

“Peak Hours” shall mean all hours of each day which are not Off-Peak Hours.

“Performance Default” shall mean the default by either party to a Partial Requirements Capacity and Energy Agreement, a Transmission Agreement, a Network Service Agreement, or a Joint Marketing Agreement, whereby, as provided by the terms of each such Agreement, such party fails to comply, after any notice of such failure and opportunity to cure, with any of the respective terms, conditions, obligations or covenants of such Agreement.

"Person" shall mean an individual, partnership, association, limited liability company, corporation, membership corporation, business trust, joint stock company, trust, cooperative, unincorporated organization, joint venture, or other entity.

"Planning Contract Member" shall mean a Partial Requirements Member which has contracted separately from the Partial Requirements Capacity and Energy Agreement to obtain Planning Services from AEPCO.

"Planning Services" shall mean bulk power supply planning and Future Resource procurement services.

"Pooled Loads" shall mean the aggregate total electric load and sales of the parties that are to be served by Pooled Resources, including distribution losses and not including reserves or transmission losses.

"Pooled Resources" shall mean those Resources which have been committed to the Resource Pool.

"Power Factor" shall mean the cosine of the phase angle □ between the voltage and the current. Power Factor can be lagging or leading indicating whether the current is lagging or leading the applied voltage.

"Power Purchase Resource" shall mean capacity and energy or energy purchased by a party under a contract with a term greater than one year, including any such capacity and energy or energy purchased or acquired pursuant to (i) the Public Utility Regulatory Policies Act of 1978, as it may be amended from time to time, or (ii) the Environmental Portfolio Standard set forth in A.A.C. R14-2-1618, as it may be amended from time to time, as adopted by the Arizona Corporation Commission.

"Power Sale(s)" shall mean a wholesale sale of capacity or energy for a term of one year or more. Power Sales do not include Retail Sales.

"Power Sales Load" shall mean the demand and energy requirements of the load associated with Power Sales Resource(s).

"Power Sales Resource" shall mean a sale of capacity and energy or energy from AEPCO Resources made by AEPCO with a contract term greater than one year (other than sales to Class A Members pursuant to a Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement) including sales to Class B and Class C Members of AEPCO.

"Pre-Closing" shall mean the execution and delivery of all documents that are a condition to Closing, as further described in the Closing Memorandum.

"Project Approval" shall mean the approval required by Section 3.4.5 of the Partial Requirements Capacity and Energy Agreement for a Resource Modification.

"Prudent Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to include a spectrum of possible practices, methods, or acts generally acceptable in the region that could be expected to accomplish the desired result at a reasonable cost consistent with reliability, safety and expedition in light of the circumstances.

"Rate Schedule A" shall mean Schedule A to the Partial Requirements Capacity and Energy Agreement.

"REAct" shall mean the Rural Electrification Act of 1936.

"Receipt Point" shall mean the interconnection between the TTS and the transmission, sub-transmission, generating resource or distribution facilities at which TRANSCO is to accept capacity or energy from AEPCO Resources for delivery pursuant to the Transmission Agreement or Network Service Agreement, and from which TRANSCO provides transmission service to the Delivery Point.

"Resource" shall mean either a Generating Resource or Power Purchase Resource.

"Resource Acquisition" shall mean the performance of analyses of Resource needs or Resource sales proposals, the recommendation of a Power Purchase Resource or Generating Resource, and the negotiation of and acquisition for AEPCO of a Resource.

"Resource Deficiency" shall mean a deficiency in AEPCO Resources available to serve Class A Members and Power Sales Loads.

"Resource Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending upon the earlier of: (a) the twentieth anniversary thereafter or (b) the last service date of a Class A Member's Wholesale Power Contract, as set forth in the Resource Planning Policies.

"Resource Integration Agreement" shall mean the multi-party agreement, in the form attached as Exhibit C to the Member Agreement, by and between CSP, TRANSCO, AEPCO and MEC and dated July 2, 2001, as amended to include SSVEC as a party.

"Resource Modification" shall mean any addition, improvement, repair or modification to an AEPCO Generating Resource or the modification or extension of the term of an existing AEPCO Power Purchase Resource made by AEPCO which would: (i) increase the capacity of the AEPCO Resource by more than ten percent; or (ii) result in an increase of more than five percent in AEPCO's Revenue Requirement upon the operation of such addition, improvement, repair and modification, or extension, as the case may be, or (iii) require an extension of the term of an Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement. A Resource Modification shall not be construed to include a Minor Resource Modification.

"Resource Operation Policies" shall mean the resource operation policies set forth in Schedule B to the Resource Integration Agreement.

"Resource Planning" shall mean the process used to identify a deficiency in the amount of existing Resources needed to reliably meet anticipated load requirements (including reserves). Resource Planning includes a review of alternative Resources and the selection of the preferred Resources to be constructed or acquired to meet the deficiency.

"Resource Planning Policies" shall mean the resource planning policies set forth in Schedule C to the Resource Integration Agreement.

"Resource Pool" shall mean the capacity and energy pool which integrates the electric capacity and associated energy of AEPCO Resources with Resources owned or contracted for by the Partial Requirements Members and CSP, which the Partial Requirements Member or CSP is required to include or has designated for inclusion in such pool.

"Resource Pool Operation" shall mean that load and resource integration service provided by AEPCO.

"Resource Pooling Policies" shall mean the resource pooling policies set forth in Schedule A of the Resource Integration Agreement.

"Restructuring Agreement" shall mean the Restructuring Agreement as executed and delivered by and among AEPCO, TRANSCO and CSP, dated the 11th day of October, 2000.

"Retail Sales" shall mean sales arranged or made by CSP in the competitive retail electric market, including sales at retail from Surplus AEPCO Resources. Retail Sales do not include Power Sales.

"Revenue Shortfall" shall mean the failure of a cooperative to receive sufficient revenue to cover its revenue requirement.

"Rights of Way" shall mean the various rights of way and easements held by TRANSCO from time to time.

"RUS" shall mean the Rural Utilities Service, as successor-in-interest to the Rural Electrification Administration, which is an agency of the United States Department of Agriculture, or any agency of the Government succeeding to its powers and functions

"Scheduling Party" shall mean the owner of an Optional Pool Resource that qualifies to be a Pooled Resource but is not included in the Resource Pool and which is separately scheduled by such owner.

"SEC" shall mean the Securities and Exchange Commission, or any agency of the Government succeeding to its powers and functions

"Service Agreement" shall mean the agreement entered into by a transmission customer or network customer and TRANSCO for transmission service or network service under Part II or Part III respectively, of the TRANSCO Tariff.

"Service Agreement(s) for Firm and Non-Firm Transmission and Ancillary Services" shall mean any Service Agreement by and between TRANSCO and AEPCO for transmission service pursuant to Part II of the TRANSCO tariff, substantially in the form of agreement attached to the TRANSCO Tariff.

"Southwest" shall mean TRANSCO.

"SSVEC" shall mean Sulphur Springs Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Staffing Agreement" shall mean each of the individual staffing agreements whereby CSP shall furnish personnel services to TRANSCO or AEPCO, respectively.

"Standards of Conduct" shall mean the Separation of Functions and Standards of Conduct as set forth as Schedule F to the Resource Integration Agreement.

"Stranded Costs" shall mean any actual charge or cost (including any transmission or distribution surcharges, fee, competition transition charge, wires charge, adjustment, rate, system benefit charge, regulatory charge, regulatory asset surcharge, exit fee or any other mechanism or systematic recovery program approved for use for the recovery of stranded investments) that are permitted by the ACC pursuant to the ACC Electric Competition Rules, A.A.C. R14-2-1601, et seq. or successor rule, or otherwise assessed or levied in order to recover the expenses and liabilities associated with stranded investments including without limitation, regulatory assets, or costs associated with the introduction of competition in the retail sales of electric energy and capacity.

"System Facilities" shall mean the transmission lines, substation facilities or components thereof and firm wheeling purchased by TRANSCO, which do not constitute Direct Assignment Facilities and are used to deliver capacity and energy to the Members and other transmission customers of TRANSCO.

"Times Interest Earned Ratio" or "TIER" shall mean the financial ratio determined based on figures shown on Form 12 Balance Sheet for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) net patronage capital or margins and (b) Interest Expense on long-term Indebtedness, and (2) dividing the sum obtained by Interest Expense on long-term Indebtedness.

"Total Assets" shall mean an amount constituting the total assets of a Class A Member determined in accordance with Accounting Requirements.

"TRANSCO" which is also known as "Southwest" shall mean Southwest Transmission Cooperative, Inc., a non-profit corporation organized under the Laws of the State of Arizona.

"TRANSCO Assumed AEPCO Debt" shall mean that portion of AEPCO's Indebtedness that TRANSCO assumes pursuant to the TRANSCO CFC Note (if required), the TRANSCO FFB Note(s), the TRANSCO RUS Note(s) and the TRANSCO Assumption and Indemnity Agreements, in each case, in accordance with applicable Law.

"TRANSCO Assumption and Indemnity Agreements" shall mean collectively the Assumption and Indemnity Agreements between TRANSCO and AEPCO and the trustees of certain financial instruments, the forms of which are set forth in Appendix A to the Restructuring Agreement pursuant to which TRANSCO will agree to assume the obligation to pay that portion of AEPCO's debt secured under the AEPCO Mortgage that AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO By-laws" shall mean the by-laws, in the form adopted by the TRANSCO Board of Directors or the TRANSCO Members, as appropriate.

"TRANSCO Employees" shall mean all persons employed by TRANSCO, including TRANSCO Management and systems operations personnel designated by the chief executive officer of TRANSCO, but shall not include persons employed by CSP or any other contractor.

"TRANSCO FFB Note(s)" shall mean the note(s) in the form required by FFB pursuant to which TRANSCO will assume and replace AEPCO as an obligor with respect to that portion of AEPCO's Indebtedness to the FFB outstanding as of the Effective Date that each of AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO Member" or "Southwest Member" shall mean any of the Class A Members of TRANSCO, and others, including AEPCO and CSP, that become members of TRANSCO in accordance with the TRANSCO By-laws.

"TRANSCO Mortgage" shall mean the Mortgage and Security Agreement, dated as of the Effective Date, made by and among TRANSCO, RUS and CFC which secures the TRANSCO Secured Obligations.

"TRANSCO Notes" shall mean written instruments or notes which evidence the obligation of TRANSCO for its assumption of a portion of the AEPCO Indebtedness (the TRANSCO Assumed AEPCO Debt) to purchase the Transmission Business as evidenced and effected by delivery of the TRANSCO FFB Note(s) and the TRANSCO RUS Note(s), payable to or guaranteed by the Government, acting through the RUS, and by its assumption of the repayment obligations of a portion of the loans made by, or securities issued to, or obligations undertaken to the Financial Entities, and which in the future will also include written instruments which may evidence additional or new loans or advances TRANSCO may obtain to finance the construction or purchase of new facilities for the TTS or the modification of existing TTS facilities, as applicable.

"TRANSCO RUS Note" shall mean the simple allocation of the AEPCO Note owed to RUS.

"TRANSCO Secured Obligations" shall mean, collectively, the TRANSCO Notes, certain of the loans made by others to TRANSCO, or securities issued to others by TRANSCO, or debt obligations entitled to the lien created by the TRANSCO Mortgage.

"TRANSCO Tariff" or "Southwest Tariff" shall mean the open access transmission tariff under which transmission services and Ancillary Services are offered by TRANSCO.

"TRANSCO Transmission System" or "TTS" shall mean the electric transmission system of TRANSCO including all transmission lines, substations, microwave and telecommunication facilities, system control and data acquisition system, inventories, works in progress, contract rights to provide or receive transmission services, leases, interests in joint transmission projects, licenses, other related transmission agreements and all other such transmission related assets.

"Transferee" shall mean any of the following Persons: (i) the Person formed as a result of a Member Transaction by any consolidation of the Partial Requirements Member with any other Person; (ii) the survivor of any merger or reorganization of the Partial Requirements Member; (iii) or a Person that acquires or leases all or substantially all of the electric assets of the Partial Requirements Member.

"Transmission Business" shall mean the performance of transmission services and Ancillary Services, and the ownership and use of any rights, obligations, duties, approvals and licenses to the Non-Generation Assets, including the Transmission Resources, and shall include responsibility for the Non-Generation Liabilities.

"Transmission Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending at least the tenth anniversary thereafter.

"Transmission Planning" shall mean the process by which the performance of an electric transmission system is evaluated with respect to specified load-serving capability in accordance with Prudent Utility Practice and by which future modifications, improvements and additions to such electric transmission system are determined by TRANSCO.

"TRICO" shall mean TRICO Electric Cooperative, Inc., a non-profit corporation organized and existing under the Laws of the State of Arizona.

"TSEPP" shall mean TSE Promotional Products, Inc., an Arizona corporation.

"TTS" shall mean TRANSCO Transmission System.

"Wholesale Power Contract" shall mean a contract, including its amendments and modifications, including the Existing Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement, between AEPCO and a Class A Member of AEPCO, for the wholesale sale by AEPCO of electric power or electric power and transmission services to such Class A Member.

"Withdrawal Agreement" shall mean the form of withdrawal agreement attached to the Member Agreement as Exhibit D.

INDEX

Definitions

MASTER AMENDMENT

TO

PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT
BETWEEN
ARIZONA ELECTRIC POWER COOPERATIVE, INC. (AEPCO)
AND
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. (SSVEC)

AND

TRANSMISSION AGREEMENT
BETWEEN
SOUTHWEST TRANSMISSION COOPERATIVE, INC. (TRANSCO)
AND
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. (SSVEC)

AND

SECOND AMENDMENT
TO THE
PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT
BETWEEN
ARIZONA ELECTRIC POWER COOPERATIVE, INC. (AEPCO)
AND
MOHAVE ELECTRIC COOPERATIVE, INC. (MEC)

AND

SECOND AMENDMENT
TO THE
TRANSMISSION AGREEMENT
BETWEEN
SOUTHWEST TRANSMISSION COOPERATIVE, INC. (TRANSCO)
AND
MOHAVE ELECTRIC COOPERATIVE, INC. (MEC)

This Master Amendment to Partial Requirements Capacity and Energy Agreement between AEPCO and SSVEC and Transmission Agreement between TRANSCO and SSVEC and Second Amendment to Partial Requirements Capacity and Energy Agreement between AEPCO and MEC and Second Amendment to Transmission Agreement between TRANSCO and MEC (the "Master Amendment") is entered into by and among Arizona Electric Power Cooperative, Inc. ("AEPCO") and Southwest Transmission Cooperative, Inc. ("TRANSCO"), each organized under the laws of the State of Arizona as non-profit electric generation and transmission cooperative corporations; and Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") and Mohave Electric Cooperative, Inc. ("MEC"), each organized under the laws of the State of Arizona as electric cooperative non-profit corporations. SSVEC and MEC each are defined as "Partial Requirements Members" as set forth in Appendix A, entitled, "Definitions as Amended and Restated as of the Agreement Date", to the Partial Requirements Capacity and Energy Agreement between AEPCO and SSVEC, dated December 29, 2005 ("Restated Appendix A"). AEPCO, TRANSCO, SSVEC and MEC shall also be referred to herein individually as "Party" and collectively as "Parties."

WHEREAS, AEPCO and SSVEC entered into the Partial Requirements Capacity and Energy Agreement, dated December 29, 2005 (the "SSVEC Partial Agreement"), which provided, among other things, in Section 15, thereof, that it shall become effective upon the Agreement Date, which is defined in Restated Appendix A as the first day of the month following the date upon which the SSVEC Partial Requirements Capacity and Energy Agreement, the SSVEC Transmission Agreement and the Resource Integration Agreement, as amended to include SSVEC, shall have been executed and delivered by the necessary parties and approved by the RUS and, if required, by the ACC and FERC; and

WHEREAS, TRANSCO and SSVEC entered into the Transmission Agreement, dated December 29, 2005 (the "SSVEC Transmission Agreement"), which provided, among other things, in Section 2, thereof, that it shall become effective on the date that the SSVEC Partial Agreement is effective, the Agreement Date, as defined in Restated Appendix A, subject to an acceptance for filing requirement, if any, by FERC; and

WHEREAS, AEPCO and MEC entered into the Second Amendment to the Partial Requirements Capacity and Energy Agreement, dated December 29, 2005 (the "Second MEC Partial Amendment"), which provided, among other things, in Section 1, thereof, that it shall become effective on the date that the SSVEC Partial Agreement is effective, the Agreement Date, as defined in Restated Appendix A; and

WHEREAS, AEPCO and MEC entered into the Second Amendment to the MEC Transmission Agreement, dated December 29, 2005 (the "Second MEC Transmission Amendment"), which provided, among other things, in Section 1, thereof, that it shall become effective on the date that the SSVEC Partial Agreement is effective, the Agreement Date, as defined in Restated Appendix A; and

WHEREAS, the Parties intend that all capitalized words used and not defined herein shall have the respective meanings as set forth in Restated Appendix A; and

WHEREAS, the Parties intend by these presents to amend and to modify the date that the SSVEC Partial Agreement, the SSVEC Transmission Agreement, the Second MEC Partial Amendment and the Second MEC Transmission Agreement become effective. The SSVEC Partial Agreement, the SSVEC Transmission Agreement, the Second MEC Partial Amendment and the Second MEC Transmission Amendment shall also be referred to herein collectively as the "Subject Documents."

NOW THEREFORE, in consideration of the premises set forth above and for other good and valuable consideration the receipt and sufficiency of which the Parties hereby acknowledge, the Parties hereto, intending to be legally bound, mutually agree as follows:

Section 1. Amendment to the SSVEC Partial Agreement.

Section 15.0 of the SSVEC Partial Agreement shall be deleted in its entirety and replaced with the following:

"15. EFFECTIVENESS AND TERM:

This Agreement is dated as of the date of execution and shall become effective upon the later of October 1, 2006, or the first day of the month following the Agreement Date, and, unless terminated by AEPCO in accordance with Section 14.1.2, shall remain in effect until December 31, 2035, unless extended further pursuant to Sections 3.3 and 3.4 hereof by the written agreement, consent or notice of Member given pursuant to Section 3 hereof. After December 31, 2035 (or such date to which the term hereof may have been extended), the Parties will enter into negotiations to determine their future relationship, if any, recognizing the past revenue payment which Member has made in support of the AEPCO Resources."

Section 2. Amendment to the SSVEC Transmission Agreement.

Section 2 of the SSVEC Transmission Agreement shall be deleted in its entirety and replaced with the following:

"2. EFFECTIVENESS AND TERM:

This Agreement is dated as of the date of execution and shall become effective upon the later of October 1, 2006, or the first day of the month following the Agreement Date, subject to an acceptance for filing requirement, if any, by FERC. This Agreement shall remain in effect concurrently with the SSVEC Partial Requirements Capacity and Energy Agreement, provided, however, that no termination of this Agreement shall occur until such termination is accepted by FERC, if required, and all of the conditions set forth in Section 15 herein have been fully satisfied."

Section 3. Amendment to the Second MEC Partial Amendment.

Section 1 of the Second MEC Partial Amendment shall be deleted in its entirety and replaced with the following:

"Section 1. Agreement Date.

This Second MEC Partial Amendment, once executed and delivered by the Parties, shall be effective upon the later of October 1, 2006, or the first day of the month following the Agreement Date. Should the RUS reject or require as a condition of the approval of this Second MEC Partial Amendment any material changes or material modifications to this Second MEC Partial Amendment that are unacceptable to any Party, the Parties shall negotiate in good faith to modify, within 60 days of receipt of the notice from RUS of such rejection or unacceptable requirement(s), this Second MEC Partial Amendment so as to attempt to secure the approval of RUS."

Section 4. Amendment to the Second MEC Transmission Amendment.

Section 1 of the Second MEC Transmission Amendment shall be deleted in its entirety and replaced with the following:

"Section 1. Agreement Date.

This Second MEC Transmission Amendment, once executed and delivered by the Parties, shall be effective upon the later of October 1, 2006, or the first day of the month following the Agreement Date, subject to an acceptance for filing requirement, if any, by FERC. Should the RUS reject or require as a condition of the approval of this Second MEC Transmission Amendment any material changes or material modifications to this Second MEC Transmission Amendment that are unacceptable to any Party, the Parties shall negotiate in good faith to modify, within sixty (60) days of receipt of the notice from RUS of such rejection or unacceptable requirement(s), this Second MEC Transmission Amendment so as to attempt to secure the approval of RUS."

Section 5. Miscellaneous.

5.1 Definitions. All capitalized terms used and defined herein shall have the meaning set forth in this Master Amendment, and are defined solely for use with this Master Amendment. All capitalized terms used and not defined herein shall have the respective meanings as set forth in Restated Appendix A, as amended herein.

5.2 Extent of Amendment. Except as expressly modified herein, all of the terms and conditions of the Subject Documents are hereby ratified and confirmed and shall remain in full force and effect.

5.3 Counterparts. This Master Amendment may be executed in any number of counterparts, and all of which when taken together shall constitute one and the same instrument. The Parties hereto may execute this Master Amendment by signing any such counterpart.

5.4 Binding Effect. This Master Amendment shall be binding upon each of the Parties, as to their respective interests, and their respective successors and assigns.

IN WITNESS WHEREOF, the undersigned have duly executed this Master Amendment this _______ day of _______. 2006.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
By: Donald W. Kimball
Name: Donald W. Kimball
Title: Executive Vice President and Chief Executive Officer

ATTEST:
By: Mark W. Schwirtz
Name: Mark W. Schwirtz
Title: Senior Vice President and Chief Operating Officer

SOUTHWEST TRANSMISSION COOPERATIVE, INC.
By: Donald W. Kimball
Name: Donald W. Kimball
Title: President and Chief Executive Officer

ATTEST:
By: Larry D. Huff
Name: Larry D. Huff
Title: Senior Vice President and Chief Operating Officer

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
By: ______________________
Name: ______________________
Title: ______________________

ATTEST:
By: ______________________
Name: ______________________
Title: ______________________

MOHAVE ELECTRIC COOPERATIVE, INC.
By: ______________________
Name: ______________________
Title: ______________________

ATTEST:
By: ______________________
Name: ______________________
Title: ______________________

IN WITNESS WHEREOF, the undersigned have duly executed this Master Amendment this _______ day of _______. 2006.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
By: ______________________________
Name: Donald W. Kimball
Title: Executive Vice President and Chief Executive Officer

ATTEST:
By: ______________________________
Name: Mark W. Schwirtz
Title: Senior Vice President and Chief Operating Officer

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

By: ______________________________
Name: Donald W. Kimball
Title: President and Chief Executive Officer

ATTEST:

By: ______________________________
Name: Larry D. Huff
Title: Senior Vice President and Chief Operating Officer

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
By: Gene Manring
Name: Gene Manring
Title: President

ATTEST:
By: Curtis Nolan
Name: Curtis Nolan
Title: Secretary

MOHAVE ELECTRIC COOPERATIVE, INC.
By: ______________________________
Name: ______________________________
Title: ______________________________

ATTEST:
By: ______________________________
Name: ______________________________
Title: ______________________________

IN WITNESS WHEREOF, the undersigned have duly executed this Master Amendment this _______ day of _______. 2006.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
By: ________________________________
Name: Donald W. Kimball
Title: Executive Vice President and Chief Executive Officer

ATTEST:
By: ________________________________
Name: Mark W. Schwirtz
Title: Senior Vice President and Chief Operating Officer

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

By: ________________________________
Name: Donald W. Kimball
Title: President and Chief Executive Officer

ATTEST:

By: ________________________________
Name: Larry D. Huff
Title: Senior Vice President and Chief Operating Officer

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
By: ________________________________
Name: ________________________________
Title: ________________________________

ATTEST:
By: ________________________________
Name: ________________________________
Title: ________________________________

MOHAVE ELECTRIC COOPERATIVE, INC.
By: ________________________________
Name: Robert E. Broz
Title: Chief Executive Officer

ATTEST:
By: Sharon Sutton
Name: Sharon Sutton
Title: Administrative Assistant

EXHIBIT B

USDA Rural Development

United States Department of Agriculture
Rural Development

JUN 07 2007

Mr. Donald W. Kimball
Executive Vice President
and Chief Executive Officer
Arizona Electric Power Cooperative, Inc.
P.O. Box 670
Benson, Arizona 85602

Dear Mr. Kimball:

It is my pleasure to inform you that the Rural Development Utilities Programs – Electric Programs (Electric Programs) approved the following contracts for Arizona Electric Power Cooperative, Inc.:

- Partial Requirements Capacity and Energy Agreement between AEPCO & SSVEC (SSVEC PRA)
- Master Amendment to the SSVEC PRA and SSVEC Transmission Agreement and Second Amendment to MEC PRA and Second Amendment to MEC Transmission Agreement (Master Amendment)
- Second Amendment to Partial Requirements Capacity and Energy Agreement between AEPCO and MEC (Second Amendment to MEC PRA)
- First Amendment to the Resource Integration Agreement (First Amendment to the RIA) among AEPCO, TRANSCO and Sierra Southwest Cooperative Services, Inc. (Sierra), MEC and SSVEC (First Amendment to RIA)
- Second Amendment to the RIA by and among AEPCO, TRANSCO, Sierra, MEC and SSVEC
- SSVEC Transmission Agreement between TRANSCO and SSVEC
- Second Amendment to the Transmission Agreement between TRANSCO and MEC

RECEIVED
JUN 12 2008
EXECUTIVE DIVISION

An approved Form 28 is enclosed with each agreement for your distribution. We will keep one original of each agreement for our files. If you need further assistance, please contact Debbie Blankenship, of my staff, at 202-720-1428.

Sincerely,

VICTOR T. VU
Director
Power Supply Division
Electric Programs

Enclosures

EXHIBIT C

EXECUTION FINAL

SECOND AMENDMENT

TO THE

PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT

BETWEEN

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

AND

MOHAVE ELECTRIC COOPERATIVE, INC.

SECOND AMENDMENT

TO THE

MEC PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT

This Second Amendment to the Partial Requirements Capacity and Energy Agreement, dated July 2, 2001, as amended by First Partial Amendment, dated January 26, 2004, is made by and between Arizona Electric Power Cooperative, Inc. and Mohave Electric Cooperative, Inc. (Second MEC Partial Amendment). Arizona Electric Power Cooperative, Inc. (AEPCO) is a non-profit generation and transmission cooperative corporation organized and existing under the laws of the State of Arizona, and Mohave Electric Cooperative, Inc. (MEC) is a non-profit cooperative corporation organized and existing under the laws of the State of Arizona. AEPCO and MEC are referred to collectively herein as the "Parties."

WHEREAS, MEC and AEPCO entered into a Partial Requirements Capacity and Energy Agreement, dated July 2, 2001, as amended by First Partial Amendment, dated January 26, 2004 (MEC Partial Requirements Capacity and Energy Agreement), and MEC and TRANSCO entered into a Transmission Agreement, dated July 2, 2001, as amended by First Transmission Amendment, dated January 26, 2004 (MEC Transmission Agreement); and

WHEREAS, Sulphur Springs Valley Electric Cooperative, Inc. (SSVEC) has elected, pursuant to the Conversion Agreement, dated August 1, 2001, among AEPCO and its Class A Members, to become a Partial Requirements Member of AEPCO by entering into a Partial Requirements Capacity and Energy Agreement with AEPCO (SSVEC Partial Requirements Capacity and Energy Agreement), a Transmission Agreement with TRANSCO (SSVEC Transmission Agreement), a Supplemental Capacity and Energy Agreement with AEPCO and TRANSCO, and Amendment 1 to the Resource Integration Agreement with AEPCO, TRANSCO, Sierra Southwest Cooperative Services, Inc. (CSP) and MEC, all of which agreements shall be effective as of the Agreement Date;

WHEREAS, MEC has elected, pursuant to the Conversion Agreement, to modify certain of the provisions of the MEC Partial Requirements Capacity and Energy Agreement, including Schedule A, Schedule B and Appendix A thereof, so that such provisions correspond to the similar provisions of the SSVEC Partial Requirements Capacity and Energy Agreement, including Schedule A, Schedule B and Appendix A thereof, to be entered into contemporaneously herewith by SSVEC and AEPCO; and

WHEREAS, in preparation of Schedule B to the SSVEC Partial Requirements Capacity and Energy Agreement, the Parties determined that certain definitions contained in Schedule B to the MEC Partial Requirements Capacity and Energy Agreement referred to historic values of load data, which the Parties desire to recognize in revisions to such definitions as set forth herein.

NOW THEREFORE, in consideration of the premises set forth above and for other good and valuable consideration the receipt and sufficiency of which the Parties hereby acknowledge, the Parties hereto, intending to be legally bound, mutually agree as follows:

Section 1. Agreement Date.

This Second MEC Partial Amendment, once executed and delivered by the Parties, shall be effective upon the date when the SSVEC Partial Requirements Capacity and Energy Agreement is effective, the Agreement Date. Should the RUS reject or require as a condition of the approval of this Second MEC Partial Amendment any material changes or material modifications to this Second MEC Partial Amendment that are unacceptable to any Party, the Parties shall negotiate in good faith to modify, within 60 days of receipt of the notice from RUS of such rejection or unacceptable requirement(s), this Second MEC Partial Amendment so as to attempt to secure the approval of RUS.

Section 2. Amendment to the MEC Partial Requirements Capacity and Energy Agreement.

2.1 The page following the end of the Table of Contents of the MEC Partial Requirements Capacity and Energy Agreement shall be amended to insert the words "as Amended and Restated as of the Agreement Date" after the word "Definitions" under the label "Appendices."

2.2 The defined terms set forth in this Section 2.2 shall replace the terms of Section 1, DEFINITIONS, of the MEC Partial Requirements Capacity and Energy Agreement that correspond to the number set forth below and shall read as follows:

"1.2 "AEPCO's Revenue Requirement" shall mean the total revenues, from any source whatsoever, necessary to enable AEPCO, utilizing a twelve month test period to: (i) meet all its anticipated fixed, variable, fuel, and all other costs, obligations and expenses and payments (including all payments on account of Indebtedness of AEPCO); (ii) establish and maintain reasonable financial reserves; and, (iii) include appropriate levels of margins and working capital to satisfy, at a minimum, applicable prescribed annual coverage ratios or any other financial covenants or tests imposed by the Financial Entities, as may exist from time to time, determined in accordance with Accounting Requirements."

"1.4 "AEPCO's Revenue Requirement From Partial Requirements Members" shall mean that portion of AEPCO's Revenue Requirement From AEPCO Class A Members allocated to Partial Requirements Members in accordance with Section 5 herein and Section 3 of Rate Schedule A."

"1.11 "MEC AEPCO Sales" shall mean the demand and associated energy requirements, including any distribution losses and not including reserves or transmission losses, of those sales of MEC to wholesale buyers or to end use loads which are external to Member's Distribution Service Area of MEC for which MEC purchases capacity and energy pursuant to the MEC Partial Requirements Capacity and Energy Agreement. The demand and energy requirements of MEC AEPCO Sales shall be metered (or determined) as agreed between MEC and TRANSCO, on the basis of actual capacity and energy supplied at the applicable points of delivery."

2.3 Section 3.3.1.1 of the MEC Partial Requirements Capacity and Energy Agreement shall be deleted in its entirety and replaced with the following:

"3.3.1.1 Except as provided in this Section 3.3.1, AEPCO may not, in the case of a modification of a Resource in which Member has an ACP, without the prior written consent of the Member: (i) determine and modify the AC of Member in an Existing Resource; (ii) otherwise add or modify an Exhibit to Rate Schedule A; or (iii) modify any other provision of this Agreement, each of which might be required as a result of such Resource Modification."

2.4 The first sentence of Section 3.4.3 of the MEC Partial Requirements Capacity and Energy Agreement shall be deleted in its entirety and replaced with the following, and the remainder of Section 3.4.3 is unchanged:

"Proposal and Analysis. Except with respect to any Required Modification or Minor Resource Modification, AEPCO shall submit to the Member a document with respect to any proposed Resource Modification ("Proposal and Analysis") containing: (i) the reasons therefor; (ii) the expected benefits and the estimated cost of implementing the proposal, demonstrating a positive benefits-to-costs relationship; (iii) the effect of implementing the proposal on the Member's AC and ACP, energy and cost; and (iv) an analysis of whether the period of AEPCO Indebtedness or the term of this Agreement will be extended to fund such proposed Resource Modification. ..."

2.5 Section 3.4.5 of the MEC Partial Requirements Capacity and Energy Agreement shall be deleted in its entirety and replaced with the following:

"3.4.5 Project Approval. Any addition of, or modification to, an exhibit to Rate Schedule A as a result of: (a) a Resource Modification which is (i) an AEPCO Generating Resource; or (ii) an extension of a then-existing Power Purchase Resource, with a new or extended term of greater than five (5) years; or (b) a modification which is not a Required Modification must, in either case, be approved by a majority vote of the AEPCO Board of Directors, including an affirmative vote of at least sixty-six and two-thirds percent (66 2/3%) of the directors representing the Class A Members prior to the AEPCO Board of Directors' authorization of the principal documents necessary to obligate AEPCO to a transaction resulting in such addition or modification to an exhibit to Rate Schedule A. Any such approval obtained pursuant to this Section 3.4.5 shall constitute a "Project Approval."

2.6 In the second to last sentence of Section 5.1 of the MEC Partial Requirements Capacity and Energy Agreement, the reference to "Section 5.5" shall be changed to refer to "Section 5.6".

2.7 The first sentence of Section 5.6 of the MEC Partial Requirements Capacity and Energy Agreement shall be deleted in its entirety and replaced with the following, and the remainder of Section 5.6 is unchanged:

"At such intervals as AEPCO shall deem appropriate, but in any event not less frequently than once in each calendar year, AEPCO shall review the rates and Fixed Charge for electric energy and capacity provided hereunder, under the SSVEC Partial Requirements Capacity and Energy Agreement, and under the Existing Wholesale Power Contracts with AEPCO's All Requirements Members. ..."

2.8 Section 12.2(b)(iv)(A) of the MEC Partial Requirements Capacity and Energy Agreement shall be deleted in its entirety and replaced with the following:

"(A) the Transferee's Debt Service Coverage Ratio is at least a level of 1.25 and Times Interest Earned Ratio is at least a level of 1.25 for each of the two immediately preceding calendar years (assuming such Member Transaction had been consummated at the beginning of such two-year period);"

2.9 Section 12.2(b)(iv)(B) of the MEC Partial Requirements Capacity and Energy Agreement shall be deleted in its entirety and replaced with the following:

"(B) the Transferee's Equity equals at least 30% of its Total Assets after giving effect to such Member Transaction; and"

2.10 The last sentence of Section 16.2 of the MEC Partial Requirements Capacity and Energy Agreement shall be deleted in its entirety and replaced with the following:

"Rate Schedule A, Schedule B and Appendix A are incorporated herein by reference and all amendments thereto approved under Section 16.1 hereof shall be attached hereto and thereby incorporated herein."

2.11 Section 22.11 of the MEC Partial Requirements Capacity and Energy Agreement shall be deleted in its entirety and replaced with the following:

"22.11 <u>Attorneys Fees and Legal Expenses</u>. If any arbitration proceeding or action shall be brought to recover any amount under this Agreement, or for, or on account of any breach of, or to enforce or interpret any of the terms, covenants, or conditions of this Agreement, the prevailing Party shall be entitled to recover from the other Party, as part of the prevailing Party's costs, reasonable attorneys' fees through any appeal, the amount of which shall be fixed by the arbitrators or by the court, and shall be made a part of any award or judgment rendered."

Section 3. Amendment to Schedule A, Rates.

3.1 Section 2.1 of Rate Schedule A to the MEC Partial Requirements Capacity and Energy Agreement shall be deleted in its entirety and replaced with the following:

"2.1 Applicability.

The rates, Fixed Charge and methodology for setting such rates, charges and adjustments is set forth in this Rate Schedule A and shall only apply to Member. Member shall make payment for electric service under this Agreement through the rates and Fixed Charge established by AEPCO in accordance with this Agreement and this Rate Schedule A. As a Partial Requirements Member, Member shall remain obligated at all times during the term of the Agreement, including periods in which a Force Majeure has been declared, to pay its Fixed Charge and O&M charge as determined in accordance with this Rate Schedule A."

3.2 Section 3.1 of Rate Schedule A shall be deleted in its entirety and replaced with the following:

"3.1 Rate Administration.

The Board of Directors of AEPCO shall review the level of revenues generated by the rates and Fixed Charges set forth in Exhibits A-1 to Rate Schedules A and revenues generated from other rates and charges to the Class A Members, together with revenues generated from all other sources, to determine their sufficiency to meet AEPCO's Revenue Requirement. In the event that the rates and Fixed Charges as set forth in Exhibits A-1 to Rate Schedules A do not provide revenues sufficient, but only sufficient, to satisfy AEPCO's Revenue Requirements From Partial Requirements Members, the Board of Directors of AEPCO shall establish new rates and new Fixed Charges, for electric service to the Partial Requirements Members pursuant to the procedures set forth in Section 5.6 of the Agreement and otherwise comply with those provisions pertaining to rates and the Fixed Charge as set forth in Section 5 of the Agreement. Such new rates and Fixed Charges established in conjunction with new rates for the All Requirements Members shall be submitted to the RUS and shall become effective unless they have been disapproved in writing by the RUS and Exhibits A-1 (and other Exhibits, as may be applicable) to Rate Schedules A shall be modified to reflect the new rates and Fixed Charges in effect."

3.3 The last paragraph of Section 3.2 of Rate Schedule A shall be deleted in its entirety and replaced with the following:

"The fixed, O&M and energy components of AEPCO's Revenue Requirement From Partial Requirements Members shall be developed from the fixed, O&M and energy components of AEPCO's Revenue Requirement From AEPCO's Class A Members pursuant to Exhibit A-2 to Rate Schedule A."

3.4 The first sentence of Section 3.4 of Rate Schedule A shall be deleted in its entirety and replaced with the following, and the remainder of Section 3.4 is unchanged:

"Once the components of fixed, O&M and energy for AEPCO's Revenue Requirements From Partial Requirements Members are determined pursuant to Section 3.2, and all expenses are classified pursuant to Section 3.3, the rates and Fixed Charge to be charged pursuant to the Agreement shall be determined in accordance with Exhibit A-2. ..."

3.5 Section 1, INTRODUCTION of Exhibit A-2 to Rate Schedule A shall be deleted in its entirety and replaced with the following:

"This Exhibit A-2 specifies the methodology for the development of rates and Fixed Charge applicable for Resources in which Member has an ACP. This methodology shall be applied to AEPCO expenses and revenues described herein, which are maintained under the Uniform System of Accounts and classified as (a) fixed, (b) O&M, or (c) energy. All amounts described hereunder and included in such accounts shall be those amounts recorded in AEPCO's financial records for the test period used in the applicable cost of service study from which the rates and Fixed Charge are to be developed. Such amounts when adjusted for appropriate credits and normalized with appropriate adjustments are the AEPCO costs and expenses which shall be used as the basis for the cost of service which determines AEPCO's Revenue Requirement which is the sum of: (i) revenues to be recovered from the Partial Requirements Member through charging the rates applied to its Member Billing Demand and Member Billing Energy and Fixed Charge pursuant to its Partial Requirements Capacity and Energy Agreement, plus (ii) revenues to be recovered from other Partial Requirements Members through charging rates pursuant to their Partial Requirements Capacity and Energy Agreements; plus (iii) revenues to be recovered from the All Requirements Members through charging rates pursuant to their Existing Wholesale Power Contracts, plus (iv) AEPCO revenues from all other sources."

3.6 Section 3.1 of Exhibit A-2 to Rate Schedule A shall be deleted in its entirety and replaced with the following:

"3.1 Purpose and Elements.

The purpose of this Section 3.1 and Sections 3.2 and 3.3 hereof is to set forth the methodology for the development of the rates and Fixed Charges attributable to electric service under the Partial Requirements Capacity and Energy Agreements. The fixed capacity component and the O&M component shall be used to calculate and determine the Fixed Charges as provided in Section 5.2 hereof, and the O&M rates as provided in Section 5.3 hereof."

3.7 The first sentence of Section 3.2 of Exhibit A-2 to Rate Schedule A shall be deleted in its entirety and replaced with the following, and the remainder of Section 3.2 is unchanged:

"3.2 Fixed Capacity Component.

The fixed capacity component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as fixed, as applicable pursuant to Section 2 hereof, to the extent attributable to the AEPCO

Resources in which Member has an ACP: …"

3.8 The first sentence of Section 3.3 of Exhibit A-2 to Rate Schedule A shall be deleted in its entirety and replaced with the following, and the remainder of Section 3.3 is unchanged:

"3.3 O&M Component.

The O&M component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as O&M, as applicable pursuant to Section 2 hereof, to the extent attributable to the AEPCO Resources in which Member has an ACP: …"

3.9 The first sentence of Section 4.0 of Exhibit A-2 to Rate Schedule A shall be deleted in its entirety and replaced with the following, and the remainder of Section 4.0 is unchanged:

"4.0 ENERGY COMPONENT:

The energy component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as energy, as applicable, pursuant to Section 2 hereof, to the extent attributable to the AEPCO Resource in which Member has an ACP: …"

3.10 The first sentence of Section 5.4 of Exhibit A-2 to Rate Schedule A shall be deleted in its entirety and replaced with the following, and the remainder of such Section 5.4 is unchanged:

"The energy rate for the Partial Requirements Member shall equal the energy component comprised of the expenses (which expenses shall include the energy charges of the PGR PPA until otherwise mutually agreed), less revenue credits as calculated in Section 4.0 of this Exhibit A-2, divided by the aggregate test year energy billing units (stated in kWh) developed in the cost of service study for the Class A Members. …"

3.11 The first sentence of Section 6.0 of Exhibit A-2 to Rate Schedule A shall be deleted in its entirety and replaced with the following and the remainder of such Section 6.0 is unchanged:

"Any deficiencies or shortfalls in collections of AEPCO's Revenue Requirement From Partial Requirements Members will be recovered through appropriate adjustments to: (a) the O&M rates, or (b) the margin included in the Fixed Charges for Partial Requirements Members. …"

Section 4. Amendment to Schedule B.

4.1 The first paragraph of Section 1.3 of Schedule B shall be deleted in its entirety and replaced with the following:

"All capitalized terms used and not defined in this Agreement, including this Schedule B, shall have the respective meanings as set forth in Appendix A to the Agreement. Wherever in Sections 2 through 8 of this Schedule B that the terms "Class A Total Load", "MEC Total Load" and "Total Load of All Requirements Members" occur, such terms shall mean "Class A Historic Total Load", "MEC Historic Total Load" and Total Historic Load of All Requirements Members", respectively."

4.2 Within Section 1.3 of Schedule B, the term "Class A Total Load" shall be deleted in its entirety and replaced with the following:

""Class A Historic Total Load" shall mean the sum of MEC Historic Total Load plus Total Historic Load of All Requirements Members."

4.3 Within Section 1.3 of Schedule B, the term "MEC Total Load" shall be deleted in its entirety and replaced with the following:

""MEC Historic Total Load" shall mean the historical totals of both the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of the loads located within Member's Distribution Service Area of MEC (or served from line extensions therefrom), the demand requirements of which shall be as set forth in Table B-1.1 hereof."

4.4 Within Section 1.3 of Schedule B, the term "Total Load of All Requirements Members" shall be deleted in its entirety and replaced with the following:

""Total Historic Load of All Requirements Members" shall mean the sum of the historical totals of both the demands and energy requirements served from AEPCO Resources of each of the All Requirements Members, excluding reserves and transmission losses, which shall be as set forth in Table B-1.1 hereof for purposes of this Schedule B."

4.5 Section 4.1 of Schedule B shall be deleted in its entirety and replaced with the following:

"4.1 Mutual Cooperation. AEPCO has in the past experienced and may in the future encounter minimum loading problems on the Apache Units 2 and 3 during periods of lower loads. Such minimum loading problems may arise in part because of the requirements of certain Power Purchase Resources of AEPCO to schedule and use energy during such periods. Purchases of supplemental energy by MEC during such load periods may aggravate this problem. In order to avoid aggravating this minimum loading problem, MEC shall share in minimum energy obligations with respect to the Apache Units 2 and 3 and the must-run requirements of certain Power Purchase Resources of AEPCO during such periods. AEPCO shall be responsible for similar minimum energy obligations determined for All Requirements Members and Power Sales Loads."

4.6 Section 4.2.1.1 of Schedule B shall be deleted in its entirety and replaced with the following:

"4.2.1.1Class A Historic Total Load is calculated by adding the average demands of the Total Historic Load of All Requirements Members from Table B-1.1, to the average demands of MEC Historic Total Load from Table B-1.1 for the same month."

4.7 "ATTACHMENT A" to Schedule B shall be deleted in its entirety and replaced with "ATTACHMENT A TO SCHEDULE B" attached and a part hereof.

Section 5. Amendment to Appendix A.

"APPENDIX A TO THE PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT, DEFINTIONS" shall be deleted in its entirety and replaced with "APPENDIX A, DEFINITIONS AS AMENDED AND RESTATED AS OF THE AGREEMENT DATE", which is attached and a part hereof.

Section 6. Miscellaneous.

6.1 Extent of Amendment. Except as expressly modified herein, all of the terms and conditions of the MEC Partial Requirements Capacity and Energy Agreement are hereby ratified and confirmed and shall remain in full force and effect.

6.2 Counterparts. This Second MEC Partial Amendment may be executed in any number of counterparts, and all of which when taken together shall constitute one and the same instrument. The Parties hereto may execute this Second MEC Partial Amendment by signing any such counterpart.

6.3 Binding Effect. This Second MEC Partial Amendment shall be binding upon the Parties, and their respective successors and assigns.

IN WITNESS WHEREOF, the undersigned have duly executed this Second MEC Partial Amendment this 29th day of December, 2006.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

By: Donald W. Kimball
Name: Donald W. Kimball
Title: Executive Vice President and Chief Executive Officer

ATTEST:

By:
Name: Mark W. Schwirtz
Title: Senior Vice President and Chief Operating Officer
Dated: ______________, 2006

MOHAVE ELECTRIC COOPERATIVE, INC.

By: ______________
President

ATTEST:

____
Secretary

Dated: ______________, 2006

ATTACHMENT A TO SCHEDULE B

GLOSSARY OF ABBREVIATIONS USED IN TABLES AND EXHIBITS

"AC" - Allocated Capacity

"ACP" - Allocated Capacity Percentage

"AEPCO" - Arizona Electric Power Cooperative, Inc.

"Avg" - Average

"Base" – Power Sales Loads solely from Base load units, Apache Steam Units 2 and 3

"CROD" - Contract Rate of Delivery

"Del'd" - Delivered

"DOW" - Day of Week

"Max" - Maximum

"Max CC" - Maximum Coal Capacity

"MEC" - Mohave Electric Cooperative, Inc.

"Min CC" - Minimum Coal Capacity

"MW" - Megawatts

"MW&E" - Morenci Water & Electric

"MWh" - Megawatt-hours

"Reqs" - Requirements

"SLCA-IP" - Salt Lake City Area Integrated Projects

"w/o" - without

APPENDIX A

DEFINITIONS AS AMENDED AND RESTATED AS OF THE AGREEMENT DATE

1. These Definitions shall have the respective meanings set forth herein for use in the following agreements and their exhibits and schedules (unless the context in which the term is used in a particular agreement clearly requires otherwise):

   1. MEC Partial Requirements Capacity and Energy Agreement;
   2. Resource Integration Agreement;
   3. MEC Transmission Agreement;
   4. Network Service Agreement;
   5. SSVEC Partial Requirements Capacity and Energy Agreement; and
   6. SSVEC Transmission Agreement.

   hereinafter referred to as "Agreements."

2. These Definitions shall not be amended or modified without advance notice, review and approval by all parties to any of the Agreements, and RUS (as hereinafter defined), which remain executory, and after providing to all parties in advance a listing of any such Agreements in which a proposed amended or modified defined term is contained.

3. The following shall be used in interpreting these Definitions and the Agreements:

   3.1 Unless otherwise required by the context in which any term appears:

   (a) Capitalized terms used in any Agreement shall have the meanings specified in this Appendix A or, if used solely within an Agreement, as set forth in such Agreement.

   (b) The singular shall include the plural and the masculine shall include the feminine and neuter.

   (c) References to "Articles," "Sections," "Schedules," "Appendices" or "Exhibits" shall be to articles, sections, schedules, appendices, or exhibits of the Agreement(s) specified, and references to paragraphs shall be to separate paragraphs of the section or subsection in which the reference occurs.

   (d) The words "herein," "hereof", "hereinbelow" and "hereunder" shall refer to an Agreement, specified as a whole and not to any particular section or subsection of such Agreement; the words "include," "includes" or "including" shall mean "including, but not limited to"; and the words "best effort(s)" shall mean a level of effort which, in the exercise of reasonable judgment in the light of facts known at the time a decision is made, can be expected to accomplish the desired result at a reasonable cost, consistent with Prudent Utility Practice (as hereinafter defined).

(e) Except where the context otherwise indicates, the term "day" shall mean a calendar day, and whenever an event is to be performed by a particular date, or a period ends on a particular date, and the date in question falls on a weekend, a legal holiday in the State of Arizona, or a day when the relevant cooperative is not open for business, the event shall be performed, or the period shall end, on the next succeeding business day.

(f) All accounting terms not specifically defined herein or by specified Accounting Requirements (as hereinafter defined) shall be construed in accordance with Generally Accepted Accounting Principles in the United States of America, consistently applied.

3.2 All references herein to the term "cooperative" shall be to AEPCO, TRANSCO, CSP or a Member (as hereinafter defined) cooperative as appropriate from the context in an Agreement.

3.3 All references to a particular entity shall include such entity's successor and permitted assigns.

3.4 All references herein to any agreement, including its schedules, exhibits and appendices, shall be to such agreement as amended, supplemented or modified.

3.5 All references herein to any Law (as hereinafter defined) shall be to such Law as amended, supplemented, modified or replaced.

3.6 The titles of the articles and sections of the Agreements have been inserted as a matter of convenience of reference only and shall not control or affect the meaning or construction of any of the terms or provisions thereof.

3.7 The parties have agreed to the wording of the Agreements, and none of the provisions thereof shall be construed against one party on the ground that any party is the author of such Agreement or any part thereof.

3.8 In any defined term which begins with the word "Member*," the word Member* may be replaced with the name of a Partial Requirements Member. When the name of a Partial Requirements Member is substituted, the definition remains the same but is applicable only to the named Partial Requirements Member. For example, "Member* Transmission Service" shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of Member* to the Member* AEPCO Load. If MEC is substituted, "MEC Transmission Service means Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of MEC to MEC AEPCO Load."

"AC" shall mean Allocated Capacity, as defined hereinbelow.

"ACC" shall mean the Arizona Corporation Commission or any State of Arizona regulatory agency succeeding to its powers and functions.

"ACP" shall mean Allocated Capacity Percentage, as defined hereinbelow.

"Accounting Requirements" shall mean the requirements of any system of accounts prescribed by the RUS as long as RUS is the holder of any obligation of a cooperative; provided, however, that if a cooperative is specifically required by another Governmental Authority to employ the system of accounts prescribed by that Governmental Authority then "Accounting Requirements" means the system of accounts prescribed by that Governmental Authority; provided, further, however, that if RUS is not a holder of any obligation or, if a holder, RUS does not prescribe a system of accounts applicable to the cooperative, and the cooperative is not specifically required by another Governmental Authority to employ that entity's system of accounts, then "Accounting Requirements" means the requirements of Generally Accepted Accounting Principles or another comprehensive basis of accounting applicable to like entities conducting business similar to that of the cooperative. Generally Accepted Accounting Principles refers to a common set of accounting standards and procedures that are either promulgated by an authoritative accounting rulemaking body or accepted as appropriate due to widespread application in the United States.

"Additional AEPCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by AEPCO.

"Additional CSP Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by CSP.

"Additional TRANSCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by TRANSCO.

"Administrator" shall mean the Administrator of RUS or any other federal regulatory agency or department succeeding to the Administrator's power or functions as a lender or mortgagee to a cooperative.

"AEPCO" shall mean Arizona Electric Power Cooperative, Inc., a non-profit generation and transmission cooperative corporation organized under the Laws of the State of Arizona.

"AEPCO Available Resource(s)" shall mean that portion of AEPCO Resources representing operating reserves which can be sold on an interruptible basis and surplus to AEPCO Total Load.

"AEPCO By-law Amendments" shall mean the amendments to the AEPCO By-laws relating to governance, in the form adopted by AEPCO in accordance with the terms of the AEPCO By-laws and the Laws of the State of Arizona.

"AEPCO By-laws" shall mean the By-laws adopted and amended by the Members or Board of Directors of AEPCO in accordance with the Laws of the State of Arizona.

"AEPCO Class A Member" shall mean: (i) any Class A Member which purchases power and energy from AEPCO pursuant to any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement and is listed in Recital B to the Partial Requirements Capacity and Energy Agreement; or (ii) is determined to be a Class A member by the terms of the AEPCO By-laws.

"AEPCO Closing Date Allocation and Attribution" shall mean the allocations and attributions to be made by AEPCO on the Closing Date, as set forth in Section 2.6of the Member Agreement and Section 2.3 of the Restructuring Agreement.

"AEPCO Delivered Load" shall mean the aggregate of the demand requirements and the associated energy requirements of all electric loads served from AEPCO Resources (including distribution losses but not including reserves or transmission losses), and shall consist of:

1. The loads of All Requirements Members served from AEPCO Resources;
2. MEC AEPCO Load;
3. MEC AEPCO Sales;
4. SSVEC AEPCO Load;
5. SSVEC AEPCO Sales;
6. Power Sales Loads; and
7. CSP AEPCO Load;

(as such terms are defined herein).

"AEPCO Employees" shall mean those individuals employed by AEPCO as of the Closing Date.

"AEPCO Load Forecast" shall mean a listing of the demand and associated energy requirements of AEPCO Total Load (by month for the Resource Forecast Period) to be served from AEPCO Resources.

"AEPCO Mortgage" shall mean the Consolidated Mortgage and Security Agreement, dated as of June 14, 1989, by and among AEPCO, as mortgagor, and the Government acting through the Administrator of the RUS, and CFC, as mortgagees, as amended and consolidated, or restated from time to time, which secures the obligations thereunder and creates a lien on substantially all of the real and tangible personal property of AEPCO in favor of such mortgagees, additional substitute mortgagees and other secured parties.

"AEPCO Notes" shall mean written instruments or notes which evidence the obligation of AEPCO for loans that in whole or in part financed the construction of AEPCO's generation and transmission facilities, the payment of which is guaranteed by the Government pursuant to the REAct, and those written instruments or notes of AEPCO outstanding on the Effective Date (with respect to the MEC Partial Requirements Capacity and Energy Agreement) or the Agreement Date (with respect to the SSVEC Partial Requirements Capacity and Energy Agreement) payable to the Government evidencing loans made by the Government, acting by and through the Administrator of RUS, pursuant to the REAct, or evidencing reimbursement obligations of AEPCO to the Government with respect to the Government's guarantee of the payment of certain notes payable to the order of FFB and all amendments, supplements, extensions, and replacements to, of, or for, such notes, and loans made by, or securities issued to, or obligations undertaken to, others, including the Financial Entities. AEPCO Notes in the future will also include written instruments, which may evidence additional or new loans or advances that AEPCO may obtain to finance the construction or purchase of new facilities, Future Resources or the modification of Existing Resources, as applicable.

"AEPCO Resource" shall mean a Resource owned or purchased from others by AEPCO.

"AEPCO Retained Personnel" shall mean AEPCO management and other personnel designated as such by the chief executive officer of AEPCO.

"AEPCO Secured Obligations" shall mean the AEPCO Notes, loans made by, or securities issued to, or debt obligations entitled to the lien created by the AEPCO Mortgage.

"AEPCO Total Load" shall mean the aggregate of the demand requirements and the associated energy requirements of: (i) AEPCO Delivered Load plus, (ii) losses related thereto from the transmission of power and energy, plus, (iii) applicable only to the demand requirement computation: the greater of (a) applicable installed capacity margin, or (b) operating reserve requirements.

"Agreement Date" shall mean the first day of the month following the date upon which the SSVEC Partial Requirements Capacity and Energy Agreement, the SSVEC Transmission Agreement and the Resource Integration Agreement, as amended to include SSVEC, shall have been executed and delivered by the necessary parties and approved by the RUS and, if required, by the ACC and FERC.

"All Requirements Member" shall mean any Class A Member of AEPCO that has entered into any Wholesale Power Contract with AEPCO which provides for the purchase from AEPCO of all such Member's requirements of electric power, which as of the Effective Date consisted of ANZA, DVEC, GCEC, SSVEC AND TRICO, and which as of the Agreement Date, shall consist of ANZA, DVEC, GCEC and TRICO.

"Allocated Capacity" or "AC" shall mean the amount of capacity of AEPCO Resources from which a Partial Requirements Member is entitled to schedule energy in any month as set forth in that Member* Partial Requirements Capacity and Energy Agreement. The AC for each month for the term of such agreement is set forth in Appendix B to Exhibit A-5 to Rate Schedule A of that Agreement.

"Allocated Capacity Percentage" or "ACP" of a Class A Member shall mean the percentage allocation with respect to an AEPCO Resource, for which, if it is a Partial Requirements Member, such Member is responsible, including the allocation of electric capacity, cost responsibility and revenues, as set forth in its Partial Requirements Capacity and Energy Agreement. Appendix A to Exhibit A-5 to Rate Schedule A sets forth the ACP for each Class A Member with respect to Existing Resources.

"Ancillary Services" shall mean the ancillary services required by FERC to be made available with transmission service in accordance with the FERC pro-forma open access transmission tariff, including; but not limited to scheduling, system control and dispatch service; reactive supply and voltage control from generation sources service; regulation and frequency response service; energy imbalance service; operations reserve-spinning reserve service, and; operating reserve - supplemental reserve service, all as such terms are further defined by FERC in Order No. 888 and 889 and identified in transmission tariffs and service agreements of TRANSCO.

"Annual Planning Report" shall mean the annual written report and analysis given to AEPCO of a Class A Member's short, intermediate and long-range forecast of load and such other planning data required by the Resource Integration Agreement.

"ANZA" shall mean Anza Electric Cooperative, Inc., a non-profit electric cooperative corporation organized and existing under the Laws of the State of California.

"Applicable Additional Contract" shall mean each additional contract as set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement, which either the Restructuring Agreement or the Member Agreement requires to be executed by each party to the Agreements.

"Assignment for Security" shall mean an assignment, transfer, mortgage or pledge of a party's interest in an Agreement made as security for any obligation secured by any indenture, mortgage, deed, deed of trust, security instrument, or similar lien on its system assets, without limitation on the right of the secured party to further assign such Agreement.

"Authorized Representative" shall mean a representative designated by a party pursuant to the terms of an Agreement and authorized to act for such party in certain matters as set forth in the relevant terms of such Agreement.

"Bonds" shall mean the CFC Guaranteed Solid Waste Disposal Revenue Bonds (Series 1994A) and the CFC Guaranteed Pollution Control Revenue Refunding Bonds (Series 1997C).

"CFC" shall mean the National Rural Utilities Cooperative Finance Corporation, a corporation organized under the Laws of the District of Columbia, or similar successor agency.

"Class A Member" shall mean any entity which is or becomes such a Member of AEPCO, TRANSCO or CSP under the relevant cooperative's by-laws.

"Closing" shall mean the execution and delivery of any and all documents and the tendering, transferring or delivering of all payments required to be made or otherwise necessary or desirable to consummate the transactions contemplated by the Restructuring Agreement and the Member Agreement, including such actions and documents described in the Closing Memorandum as specified in Section 8.1 of both the Restructuring Agreement and the Member Agreement, following satisfaction or waiver, if any, of the conditions for Closing therein.

"Closing Date" shall mean the date on which the Closing occurs.

"Closing Memorandum" shall mean that memorandum agreed to by the parties to the Member Agreement prior to the Pre-Closing which sets forth the consents, assignments, transfers, delivery of other approvals, documents, legal opinions, payments and transaction documents to be furnished by the parties, other conditions for Closing, and events and actions required to effect the Closing.

"Collected Funds" shall mean deposited funds in a banking institution that are immediately available for use without any float restrictions.

"Contract Rate of Interest" shall mean the lesser of: (i) the interest rate equal to the effective "Prime Rate" per annum as specified in the "Money Rates" section of the *Wall Street Journal* or, (ii) the maximum interest rate permitted by applicable Law in the State of Arizona if any is so stated.

"CSP" shall mean Sierra Southwest Cooperative Services, Inc., a non-profit corporation organized under the generation and transmission cooperative corporation Laws of the State of Arizona.

"CSP AEPCO Load" shall mean the sum of the demand and associated energy requirements, including distribution losses, but not including reserves or transmission losses, of the Member JMP Load of each Class A Member and of those other loads for which CSP purchases capacity and energy from AEPCO as specified in separate sales agreements between AEPCO and CSP.

"CSP Assets" shall mean all capital stock of TSEPP, personal property, authorization to make Retail Sales, intangible assets, employee benefit plans, intellectual property, software licenses, employee or consultant agreements, equipment leases and contracts, licenses, any chose in action, and other agreements related to the performance of the CSP Business identified on Schedule 2 to the Restructuring Agreement.

"CSP Business" shall mean: (i) the business of power sales and retail sales; (ii) the provision of personnel and consulting services to AEPCO, TRANSCO, and others pursuant to contract; and, (iii) the ownership and use of the CSP Assets, including responsibility for CSP Liabilities.

"CSP JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of those loads within a Member's Distribution Service Area served using capacity and energy provided by CSP from CSP Resources pursuant to a Joint Marketing Agreement between a Class A Member and CSP.

"CSP Liabilities" shall mean (i) the CSP liabilities identified on Schedule 2 to the Restructuring Agreement, as such obligations exist as of the Closing Date; and (ii) such other obligations relating to the performance of the CSP Business as CSP, AEPCO and TRANSCO may agree upon from time to time in other agreements; and (iii) any liabilities which CSP assumes in accordance with its by-laws.

"CSP Member" shall mean AEPCO, TRANSCO and the Class A Members of AEPCO on the Closing Date and any Person, which has become and retains membership in CSP in accordance with the CSP By-laws.

"CSP Resource" shall mean a Resource owned or purchased by CSP from third parties.

"Debt Service Coverage Ratio" or "DSC" shall mean the financial ratio determined, based on figures shown on RUS Form 12 for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) depreciation and amortization expense, (b) interest on long-term debt (increased by one-third of the amount, if any, by which long-term leases exceed two percent of total margins and equities less regulatory assets), and (c) net patronage capital or margins and (2) dividing the sum obtained by the total of interest and principal billed under long-term debt and debt service requirements.

"Delivery Point" shall mean the interconnection between the TTS and the transmission, distribution system or load of a Class A Member at which TRANSCO is to deliver capacity or energy pursuant to the Transmission Agreement or the Network Service Agreement.

"Direct Assignment Facilities" shall mean those transmission lines, substation facilities (or components thereof) and firm wheeling purchased by TRANSCO, for the sole use and benefit of a TRANSCO Member or of a particular transmission customer receiving service under the TRANSCO Tariff.

"DVEC" shall mean Duncan Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Economy Purchase(s)" shall mean a wholesale purchase of capacity and/or energy for a term not to exceed one year (including all renewal periods) entered into by AEPCO.

"Economy Sale(s)" shall mean a wholesale sale by AEPCO of capacity and energy from AEPCO Available Resources made for monthly, daily or hourly periods of the next twelve months on a pre-scheduled basis.

"Effective Date" shall mean either (i) August 1, 2001, or (ii) the Closing Date.

"Equity" shall be defined in accordance with Accounting Requirements.

"Existing Resource(s)" shall mean the AEPCO Resource(s) as set forth in Appendix B to Exhibit A-5 to Rate Schedule A.

"Existing Wholesale Power Contract" shall mean the Wholesale Power Contract between AEPCO and a Class A Member, and when used in the plural shall mean such contract and similar contracts between AEPCO and each of the Class A Members pursuant to which, in either case, such Class A Member purchases or purchased all its requirements of electric power from AEPCO prior to its becoming a Partial Requirements Member.

"FERC" shall mean the Federal Energy Regulatory Commission, an agency of the United States Department of Energy, or regulatory agency succeeding to the powers and functions thereof.

"FFB" shall mean the Federal Financing Bank, an instrumentality and wholly owned corporation of the Government or any agency or department of the Government succeeding to the powers and functions thereof.

"Financial Entities" shall mean collectively RUS, CFC, FFB, the trustees and bondholders of the Bonds and other lending institutions or issuers of debt who have made loans to or hold securities or other obligations of a cooperative.

"First Right(s) of Refusal" shall mean reciprocal one-time rights of first refusal to sell capacity and associated energy granted by the purchasing party to the selling party pursuant to Section 10.1 of the Resource Integration Agreement. Certain conditional first rights of refusal provided by CSP to AEPCO as set forth in Section 14 of the Resource Integration Agreement shall not be deemed to form a part of this defined term.

"Force Majeure" shall mean the occurrence or non-occurrence of any act, event or cause beyond the control of a party to an Agreement whereby the party is unable to perform its obligation, other than the obligation to pay money, which act, event or cause by that party's exercise of due diligence could not have reasonably been expected and avoided, or which even with the exercise of due diligence, the party has not been able to overcome or avoid or cause to be avoided. Such act, event or cause shall include, but not be limited to: acts of God; failure or threat of immediate failure of facilities; explosions, flood, drought, earthquake, storm, fire, pestilence, lightning and other natural catastrophes; epidemic; war; riot; civil disturbance or disobedience, strike, or labor disturbance, disputes or unrest of whatever nature; civil disputes or unrest of whatever nature; labor, material or fuel shortage; sabotage; vandalism; restraint by court order or public authority; a failure or threat of failure of any generating or transmission facility, which is likely to cause an outage of electric service to customers served from that party's system (including transmission curtailments by a transmission provider) or to cause such party to experience a rapid decline in system voltage or frequency; and, action or non-action by or inability to obtain the necessary authorizations or approvals from any Governmental Authority (but not including the ACC or RUS), provided however, that no act, event or cause that is the result of the lack of necessary financial resources shall constitute an event of "Force Majeure," nor shall an act, event or cause that is the result of the negligence of the party claiming Force Majeure constitute an event of "Force Majeure."

"Form 12A Balance Sheet" shall mean RUS Form 12a, Section B, Balance Sheet.

"Future Resource" shall mean any (i) new AEPCO Generating Resource, or (ii) any AEPCO Power Purchase Resource with a term of greater than five years; either of which Resource would require the assignment of a new ACP to each Class A Member participating in such Resource and an amendment, or a new Exhibit to Rate Schedule A.

"GCEC" shall mean Graham County Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Generally Accepted Auditing Standards" shall mean a common set of auditing standards and procedures that have been developed over time by several auditing boards, the most current set of standards and procedures of which is the Auditing Standards Board.

"Generating Resource" shall mean an interest in any existing, additional, modified or re-powered generating facility or unit, which may be owned (jointly or individually), leased or otherwise acquired by a party; provided that in connection with any lease of an Existing Resource of AEPCO, such leasehold interest shall not be deemed to be a Future Resource for purposes of a Partial Requirements Capacity and Energy Agreement.

"Generation Business" shall mean with respect to AEPCO: (i) the business of generation of electricity; (ii) operation of the Resource Pool; and, (iii) the use, ownership, rights, obligations and duties associated with the generation assets including its agreements for Power Purchase Resources, Power Sales Resources, Economy Purchases and Economy Sales including, but not limited to, the Existing Wholesale Power Contracts and the Partial Requirements Capacity and Energy Agreement.

"Government" shall mean the federal government of the United States of America.

"Governmental Authority" shall mean any local, state, regional, federal, or national administrative, legal, judicial, or executive governmental agency, commission, department, or other governmental entity having jurisdiction over AEPCO, TRANSCO, CSP, their respective Members, or any of their activities.

"Indebtedness" shall mean:

(1) debt incurred or assumed by a cooperative for borrowed money, or debt incurred for the reimbursement of money advanced under any credit support agreements if in either case categorized as debt according to Accounting Requirements;

(2) lease obligations, if categorized as debt according to Accounting Requirements;

(3) debt incurred or obligations assumed for facilities or power purchases included in a Member's ACP;

(4) debt incurred or obligations issued to finance the amount of a pre-payment; or

(5) debt for any Person (other than debt otherwise treated as Indebtedness hereunder) described in clauses (1), (2), (3) or (4) above which are guaranteed (whether by payment or collection) by the cooperative, provided that none of the following shall constitute Indebtedness:

(A) guarantees of performance or payment by, or any obligations of, any Person under contracts to pay for fuel for the system; and

(B) guarantees of performance by any Person for other than payment of debt incurred or assumed for borrowed money, or any obligation if categorized as debt according to Accounting Requirements, including, without limitation, all debt (other than indebtedness otherwise treated as Indebtedness hereunder) for borrowed money or the acquisition, construction or improvement of property or capitalized lease obligations guaranteed directly or indirectly, in any manner by a cooperative, or in effect guaranteed, directly or indirectly, by such cooperative through an agreement, contingent or otherwise, to assume any such indebtedness or to advance or supply funds for the payment or purchase of any such indebtedness or to purchase property or services primarily for the purpose of enabling the debtor or seller to make payment of such indebtedness, or to assure the owner of the indebtedness against loss, because of such indebtedness or to supply funds to or in any other manner invest in the debtor (including any agreement to pay for property or services irrespective of whether or not such property is delivered or such services are rendered) or otherwise.

"Interest Expense" shall mean an amount constituting interest on long-term Indebtedness (less any interest during construction and allowance for funds used during construction including an interest rate swap collar, floor forward or other hedging agreement, arrangement or security, however denominated,) and other interest expense computed in accordance with Accounting Requirements.

"Joint Marketing Agreement" shall mean an agreement by and between CSP and a Class A Member pertaining to joint competitive retail electric marketing and sales activities, in accordance with applicable Law, within such Member's Distribution Service Area.

"Joint Marketing Plan" shall mean a plan designed by and entered into between CSP and a Class A Member concerning Retail Sales, the form of which is set forth in Exhibit B to the Joint Marketing Agreement.

"Law" shall mean any applicable treaty, statute, code, constitutional provision, ordinance, rule, regulation, order, judgment, decree, decision, injunction, process or any similar form of legally binding decision or directive issued by any Governmental Authority including permits and regulatory approvals and any applicable common law.

"Legal Requirement" shall mean any obligation of AEPCO or TRANSCO under Law.

"Load Forecast" shall mean the projections of monthly coincident peak kilowatt and total monthly kilowatt-hour loads of a party to an Agreement.

"MEC" shall mean Mohave Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Member*" shall mean a Partial Requirement Member of AEPCO.

"Member* AEPCO Load" shall have the meaning set forth in Section 1 of the Member* Partial Requirements Capacity and Energy Agreement.

"Member* AEPCO Sales" shall have the meaning set forth in Section 1 of the Member* Partial Requirements Capacity and Energy Agreement.

"Member* External Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located external to the Member's Distribution Service Area of Member* (and not served from line extensions therefrom) for which Member* sells capacity and energy from Member* Resources. The demand and energy requirements of Member* External Load are not included in Member* Metered kW and Member* Metered kWh, respectively.

"Member* Internal Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within the Member's Distribution Service Area of Member* (or served from line extensions therefrom) for which Member* sells capacity and energy from Member* Resources. The demand and energy requirements of Member* Internal Load are included in Member* Metered kW and Member* Metered kWh, respectively.

"Member* Metered kW" shall have the meaning set forth in Section 1 of the Member* Partial Requirements Capacity and Energy Agreement.

"Member* Metered kWh" shall have the meaning set forth in Section 1 of the Member* Partial Requirements Capacity and Energy Agreement.
"Member* Partial Requirements Capacity and Energy Agreement" shall mean the Partial Requirements Capacity and Energy Agreement, by and between AEPCO and Member*.

"Member* Resource(s)" shall mean a Resource of a Partial Requirements Member of AEPCO; Member Resource does not include the capacity and energy purchased from AEPCO under the Partial Requirements Capacity and Energy Agreement, or purchased by AEPCO under separate contract.

"Member* Transmission Agreement" shall mean the Transmission Agreement in the form attached as Exhibit B-2 to the Member Agreement, by and between TRANSCO and Member* for the purposes of Member* Transmission Service.

"Member* Transmission Service" shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of Member* to Member* AEPCO

Load.

"Member* Wheeling Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within Member's Distribution Service Area of Member* (or served from line extensions therefrom), which are supplied by capacity and energy from third parties (and not from Member Resources or the AC of Member*) and for which Member* provides delivery services over its distribution system. The demand and energy requirements of Member* Wheeling Load are included within Member* Metered kW and Member* Metered kWh, respectively.

"Member" shall mean a member of AEPCO, a CSP Member or a TRANSCO Member, as applicable.

"Member Agreement" shall mean the Member Agreement as executed and delivered by and among the Class A Members, AEPCO, TRANSCO and CSP, dated July 2, 2001.

"Member's Distribution Service Area" shall mean the geographical electric service territory of a Class A Member as certificated by the ACC, the California Public Utility Commission or the New Mexico Public Utility Commission, as applicable, to supply distribution service as well as all other territory so served by such Class A Member pursuant to applicable Law, or any inter-utility border agreement.

"Member JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses of loads located within a Member's Distribution Service Area served using capacity and energy provided by CSP as a result of a Joint Marketing Agreement between CSP and a Class A Member, for which CSP purchases capacity and energy from AEPCO.

"Member Transaction" shall mean: (i) the consolidation or merger by the Partial Requirements Member with any other Person; (ii) the reorganization or change of the form of the Partial Requirements Member's business organization from an electric cooperative non-profit membership-owned corporation; or, (iii) the sale, transfer, lease, or other disposal of all or substantially all the Partial Requirements Member's assets to any Person (or any effort or agreement therefor), whether accomplished in a single transaction or contemplated through a series of transactions as set forth in Section 12 of the Partial Requirements Capacity and Energy Agreement and the Transmission Agreement.

"Minor Resource Modification" shall mean an addition, improvement, repair or modification to an AEPCO Generating Resource or the modification or extension of an AEPCO Power Purchase Resource undertaken by AEPCO in its sole discretion, which will not: (i) increase of greater than ten percent the capacity of the AEPCO Resource being modified; (ii) result in an increase of greater than five percent in AEPCO's Revenue Requirement From AEPCO's Class A Members upon the operation of such addition, improvement, repair and modification or extension, as the case may be; or, (iii) extend the term of any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement.

"Must-Pool Resources" shall mean AEPCO Resources and those Resources of CSP and the Partial Requirements Member, which are required to be included in the Resource Pool.

"Native Load" shall mean: (i) for AEPCO, the electric load of wholesale power customers of AEPCO on whose behalf AEPCO, by Law, tariff or contract, has undertaken an obligation to construct, or otherwise obtain, reliably operate and provide AEPCO Resources (including Purchase Power Resources of AEPCO) to meet the electric requirements of such customers and shall include, but not be limited to, AEPCO Delivered Load, (ii) for TRANSCO, "Native Load" shall mean the electric loads of the TTS customers on whose behalf TRANSCO, by Law, tariff or contract (including as TTS successor to AEPCO) has undertaken an obligation to construct and operate the TTS and shall include, but not be limited to, AEPCO Delivered Load, and (iii) for a Member, "Native Load" shall mean the electric load of the customers of a Member to whom such Member sells power and/or energy and on whose behalf the Member, by Law, tariff, or contract, has undertaken an obligation to construct, or otherwise obtain, and reliably operate the Member's system to meet the power supply requirements of such customers.

"Net Utility Plant" shall mean total utility plant less accumulated depreciation as computed consistent with Accounting Requirements.

"Network Integration Transmission Service" shall be described in Part III of the TRANSCO Tariff.

"Network Service Agreement" shall mean the Network Service Agreement by and between TRANSCO, AEPCO and the All Requirements Members, substantially in the form attached as Exhibit B-1 to the Member Agreement.

"Non-Generation Assets" shall mean, as determined in accordance with Accounting Requirements, all assets of AEPCO of every kind, description, and location which shall be acquired by TRANSCO from AEPCO, as of the Closing Date, which are set forth in Schedule 1 to the Restructuring Agreement.

"Non-Pool Loads" shall mean those loads of a Partial Requirements Member or CSP or applicable portions of such loads which are not included in Pooled Loads.

"Non-Pool Resource" means any Resource obtained by a Partial Requirements Member or CSP and which is not included in the Resource Pool.

"O&M" shall mean the general accounting term used to describe activities and expenses involved with the use, operation, maintenance and repair of a cooperative's plant and facilities including expenses associated with activities intended to prevent or remedy an impending or actual breakdown of those facilities. The term O&M does not include the enlargement or improvement of the property owned or leased and operated by a cooperative nor does it include the replacement of retirement units.

"Off-Peak Hours" shall mean those hours defined by the Western Systems Coordinating Council to represent off-peak load periods, which for each day consist of the eight hours of the hour ending at 11:00 p.m. through hour ending at 6:00 a.m., Mountain Standard Time, and the remaining hours of each Sunday and of each of six holidays (New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day).

"Operating Committee" shall mean the standing committee(s) established in the Partial Requirements Capacity and Energy Agreement and assigned by the parties thereto to deal on a prompt and orderly basis with certain technical and operating issues that may arise in connection with system development or operations.

"Optional Pool Resources" shall mean those Resources which a party may commit to the Resource Pool.

"Order No. 888" shall mean that certain FERC order *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. para. 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. para. 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC para. 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC para. 61,046 (1998).

"Order No. 889" shall mean that certain FERC order *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, 61 Fed. Reg. 21,737 (1996), FERC Stats. & Regs. para. 31,035 (1996), *order on reh'g*, Order No. 889-A, 62 Fed. Reg. 12,484 (1997), FERC Stats. & Regs. para. 31,049 (1997), *order on reh'g*, Order No. 889-B, 81 FERC 61,253 (1997).

"Partial Requirements Member" shall mean MEC, SSVEC or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Peak Hours" shall mean all hours of each day which are not Off-Peak Hours.

"Performance Default" shall mean the default by either party to a Partial Requirements Capacity and Energy Agreement, a Transmission Agreement, a Network Service Agreement, or a Joint Marketing Agreement, whereby, as provided by the terms of each such Agreement, such party fails to comply, after any notice of such failure and opportunity to cure, with any of the respective terms, conditions, obligations or covenants of such Agreement.

"Person" shall mean an individual, partnership, association, limited liability company, corporation, membership corporation, business trust, joint stock company, trust, cooperative, unincorporated organization, joint venture, or other entity.

"Planning Contract Member" shall mean a Partial Requirements Member which has contracted separately from the Partial Requirements Capacity and Energy Agreement to obtain Planning Services from AEPCO.
"Planning Services" shall mean bulk power supply planning and Future Resource procurement services.

"Pooled Loads" shall mean the aggregate total electric load and sales of the parties that are to be served by Pooled Resources, including distribution losses and not including reserves or transmission losses.

"Pooled Resources" shall mean those Resources which have been committed to the Resource Pool.

"Power Factor" shall mean the cosine of the phase angle □ between the voltage and the current. Power Factor can be lagging or leading indicating whether the current is lagging or leading the applied voltage.

"Power Purchase Resource" shall mean capacity and energy or energy purchased by a party under a contract with a term greater than one year, including any such capacity and energy or energy purchased or acquired pursuant to (i) the Public Utility Regulatory Policies Act of 1978, as it may be amended from time to time, or (ii) the Environmental Portfolio Standard set forth in A.A.C. R14-2-1618, as it may be amended from time to time, as adopted by the Arizona Corporation Commission.

"Power Sale(s)" shall mean a wholesale sale of capacity or energy for a term of one year or more. Power Sales do not include Retail Sales.

"Power Sales Load" shall mean the demand and energy requirements of the load associated with Power Sales Resource(s).

"Power Sales Resource" shall mean a sale of capacity and energy or energy from AEPCO Resources made by AEPCO with a contract term greater than one year (other than sales to Class A Members pursuant to a Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement) including sales to Class B and Class C Members of AEPCO.

"Pre-Closing" shall mean the execution and delivery of all documents that are a condition to Closing, as further described in the Closing Memorandum.

"Project Approval" shall mean the approval required by Section 3.4.5 of the Partial Requirements Capacity and Energy Agreement for a Resource Modification.

"Prudent Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to include a spectrum of possible practices, methods, or acts generally acceptable in the region that could be expected to accomplish the desired result at a reasonable cost consistent with reliability, safety and expedition in light of the circumstances.

"Rate Schedule A" shall mean Schedule A to the Partial Requirements Capacity and Energy Agreement.

"REAct" shall mean the Rural Electrification Act of 1936.

"Receipt Point" shall mean the interconnection between the TTS and the transmission, sub-transmission, generating resource or distribution facilities at which TRANSCO is to accept capacity or energy from AEPCO Resources for delivery pursuant to the Transmission Agreement or Network Service Agreement, and from which TRANSCO provides transmission service to the Delivery Point.

"Resource" shall mean either a Generating Resource or Power Purchase Resource.

"Resource Acquisition" shall mean the performance of analyses of Resource needs or Resource sales proposals, the recommendation of a Power Purchase Resource or Generating Resource, and the negotiation of and acquisition for AEPCO of a Resource.

"Resource Deficiency" shall mean a deficiency in AEPCO Resources available to serve Class A Members and Power Sales Loads.

"Resource Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending upon the earlier of: (a) the twentieth anniversary thereafter or (b) the last service date of a Class A Member's Wholesale Power Contract, as set forth in the Resource Planning Policies.

"Resource Integration Agreement" shall mean the multi-party agreement, in the form attached as Exhibit C to the Member Agreement, by and between CSP, TRANSCO, AEPCO and MEC and dated July 2, 2001, as amended to include SSVEC as a party.

"Resource Modification" shall mean any addition, improvement, repair or modification to an AEPCO Generating Resource or the modification or extension of the term of an existing AEPCO Power Purchase Resource made by AEPCO which would: (i) increase the capacity of the AEPCO Resource by more than ten percent; or (ii) result in an increase of more than five percent in AEPCO's Revenue Requirement upon the operation of such addition, improvement, repair and modification, or extension, as the case may be, or (iii) require an extension of the term of an Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement. A Resource Modification shall not be construed to include a Minor Resource Modification.

"Resource Operation Policies" shall mean the resource operation policies set forth in Schedule B to the Resource Integration Agreement.

"Resource Planning" shall mean the process used to identify a deficiency in the amount of existing Resources needed to reliably meet anticipated load requirements (including reserves). Resource Planning includes a review of alternative Resources and the selection of the preferred Resources to be constructed or acquired to meet the deficiency.

"Resource Planning Policies" shall mean the resource planning policies set forth in Schedule C to the Resource Integration Agreement.

"Resource Pool" shall mean the capacity and energy pool which integrates the electric capacity and associated energy of AEPCO Resources with Resources owned or contracted for by the Partial Requirements Members and CSP, which the Partial Requirements Member or CSP is required to include or has designated for inclusion in such pool.
"Resource Pool Operation" shall mean that load and resource integration service provided by AEPCO.

"Resource Pooling Policies" shall mean the resource pooling policies set forth in Schedule A of the Resource Integration Agreement.

"Restructuring Agreement" shall mean the Restructuring Agreement as executed and delivered by and among AEPCO, TRANSCO and CSP, dated the 11th day of October, 2000.

"Retail Sales" shall mean sales arranged or made by CSP in the competitive retail electric market, including sales at retail from Surplus AEPCO Resources. Retail Sales do not include Power Sales.

"Revenue Shortfall" shall mean the failure of a cooperative to receive sufficient revenue to cover its revenue requirement.

"Rights of Way" shall mean the various rights of way and easements held by TRANSCO from time to time.

"RUS" shall mean the Rural Utilities Service, as successor-in-interest to the Rural Electrification Administration, which is an agency of the United States Department of Agriculture, or any agency of the Government succeeding to its powers and functions

"Scheduling Party" shall mean the owner of an Optional Pool Resource that qualifies to be a Pooled Resource but is not included in the Resource Pool and which is separately scheduled by such owner.

"SEC" shall mean the Securities and Exchange Commission, or any agency of the Government succeeding to its powers and functions

"Service Agreement" shall mean the agreement entered into by a transmission customer or network customer and TRANSCO for transmission service or network service under Part II or Part III respectively, of the TRANSCO Tariff.

"Service Agreement(s) for Firm and Non-Firm Transmission and Ancillary Services" shall mean any Service Agreement by and between TRANSCO and AEPCO for transmission service pursuant to Part II of the TRANSCO tariff, substantially in the form of agreement attached to the TRANSCO Tariff.

"Southwest" shall mean TRANSCO.

"SSVEC" shall mean Sulphur Springs Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Staffing Agreement" shall mean each of the individual staffing agreements whereby CSP shall furnish personnel services to TRANSCO or AEPCO, respectively.

"Standards of Conduct" shall mean the Separation of Functions and Standards of Conduct as set forth as Schedule F to the Resource Integration Agreement.

"Stranded Costs" shall mean any actual charge or cost (including any transmission or distribution surcharges, fee, competition transition charge, wires charge, adjustment, rate, system benefit charge, regulatory charge, regulatory asset surcharge, exit fee or any other mechanism or systematic recovery program approved for use for the recovery of stranded investments) that are permitted by the ACC pursuant to the ACC Electric Competition Rules, *A.A.C. R14-2-1601, et seq.* or successor rule, or otherwise assessed or levied in order to recover the expenses and liabilities associated with stranded investments including without limitation, regulatory assets, or costs associated with the introduction of competition in the retail sales of electric energy and capacity.

"System Facilities" shall mean the transmission lines, substation facilities or components thereof and firm wheeling purchased by TRANSCO, which do not constitute Direct Assignment Facilities and are used to deliver capacity and energy to the Members and other transmission customers of TRANSCO.

"Times Interest Earned Ratio" or "TIER" shall mean the financial ratio determined based on figures shown on Form 12 Balance Sheet for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) net patronage capital or margins and (b) Interest Expense on long-term Indebtedness, and (2) dividing the sum obtained by Interest Expense on long-term Indebtedness.

"Total Assets" shall mean an amount constituting the total assets of a Class A Member determined in accordance with Accounting Requirements.

"TRANSCO" which is also known as "Southwest" shall mean Southwest Transmission Cooperative, Inc., a non-profit corporation organized under the Laws of the State of Arizona.

"TRANSCO Assumed AEPCO Debt" shall mean that portion of AEPCO's Indebtedness that TRANSCO assumes pursuant to the TRANSCO CFC Note (if required), the TRANSCO FFB Note(s), the TRANSCO RUS Note(s) and the TRANSCO Assumption and Indemnity Agreements, in each case, in accordance with applicable Law.

"TRANSCO Assumption and Indemnity Agreements" shall mean collectively the Assumption and Indemnity Agreements between TRANSCO and AEPCO and the trustees of certain financial instruments, the forms of which are set forth in Appendix A to the Restructuring Agreement pursuant to which TRANSCO will agree to assume the obligation to pay that portion of AEPCO's debt secured under the AEPCO Mortgage that AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO By-laws" shall mean the by-laws, in the form adopted by the TRANSCO Board of Directors or the TRANSCO Members, as appropriate.

"TRANSCO Employees" shall mean all persons employed by TRANSCO, including TRANSCO Management and systems operations personnel designated by the chief executive officer of TRANSCO, but shall not include persons employed by CSP or any other contractor.

"TRANSCO FFB Note(s)" shall mean the note(s) in the form required by FFB pursuant to which TRANSCO will assume and replace AEPCO as an obligor with respect to that portion of AEPCO's Indebtedness to the FFB outstanding as of the Effective Date that each of AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO Member" or "Southwest Member" shall mean any of the Class A Members of TRANSCO, and others, including AEPCO and CSP, that become members of TRANSCO in accordance with the TRANSCO By-laws.

"TRANSCO Mortgage" shall mean the Mortgage and Security Agreement, dated as of the Effective Date, made by and among TRANSCO, RUS and CFC which secures the TRANSCO Secured Obligations.

"TRANSCO Notes" shall mean written instruments or notes which evidence the obligation of TRANSCO for its assumption of a portion of the AEPCO Indebtedness (the TRANSCO Assumed AEPCO Debt) to purchase the Transmission Business as evidenced and effected by delivery of the TRANSCO FFB Note(s) and the TRANSCO RUS Note(s), payable to or guaranteed by the Government, acting through the RUS, and by its assumption of the repayment obligations of a portion of the loans made by, or securities issued to, or obligations undertaken to the Financial Entities, and which in the future will also include written instruments which may evidence additional or new loans or advances TRANSCO may obtain to finance the construction or purchase of new facilities for the TTS or the modification of existing TTS facilities, as applicable.

"TRANSCO RUS Note" shall mean the simple allocation of the AEPCO Note owed to RUS.

"TRANSCO Secured Obligations" shall mean, collectively, the TRANSCO Notes, certain of the loans made by others to TRANSCO, or securities issued to others by TRANSCO, or debt obligations entitled to the lien created by the TRANSCO Mortgage.

"TRANSCO Tariff" or "Southwest Tariff" shall mean the open access transmission tariff under which transmission services and Ancillary Services are offered by TRANSCO.

"TRANSCO Transmission System" or "TTS" shall mean the electric transmission system of TRANSCO including all transmission lines, substations, microwave and telecommunication facilities, system control and data acquisition system, inventories, works in progress, contract rights to provide or receive transmission services, leases, interests in joint transmission projects, licenses, other related transmission agreements and all other such transmission related assets.

"Transferee" shall mean any of the following Persons: (i) the Person formed as a result of a Member Transaction by any consolidation of the Partial Requirements Member with any other Person; (ii) the survivor of any merger or reorganization of the Partial Requirements Member; (iii) or a Person that acquires or leases all or substantially all of the electric assets of the Partial Requirements Member.

"Transmission Business" shall mean the performance of transmission services and Ancillary Services, and the ownership and use of any rights, obligations, duties, approvals and licenses to the Non-Generation Assets, including the Transmission Resources, and shall include responsibility for the Non-Generation Liabilities.

"Transmission Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending at least the tenth anniversary thereafter.

"Transmission Planning" shall mean the process by which the performance of an electric transmission system is evaluated with respect to specified load-serving capability in accordance with Prudent Utility Practice and by which future modifications, improvements and additions to such electric transmission system are determined by TRANSCO.

"TRICO" shall mean TRICO Electric Cooperative, Inc., a non-profit corporation organized and existing under the Laws of the State of Arizona.

"TSEPP" shall mean TSE Promotional Products, Inc., an Arizona corporation.

"TTS" shall mean TRANSCO Transmission System.

"Wholesale Power Contract" shall mean a contract, including its amendments and modifications, including the Existing Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement, between AEPCO and a Class A Member of AEPCO, for the wholesale sale by AEPCO of electric power or electric power and transmission services to such Class A Member.

"Withdrawal Agreement" shall mean the form of withdrawal agreement attached to the Member Agreement as Exhibit D.

INDEX

Definitions

MASTER AMENDMENT

TO

PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT
BETWEEN
ARIZONA ELECTRIC POWER COOPERATIVE, INC. (AEPCO)
AND
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. (SSVEC)

AND

TRANSMISSION AGREEMENT
BETWEEN
SOUTHWEST TRANSMISSION COOPERATIVE, INC. (TRANSCO)
AND
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. (SSVEC)

AND

SECOND AMENDMENT
TO THE
PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT
BETWEEN
ARIZONA ELECTRIC POWER COOPERATIVE, INC. (AEPCO)
AND
MOHAVE ELECTRIC COOPERATIVE, INC. (MEC)

AND

SECOND AMENDMENT
TO THE
TRANSMISSION AGREEMENT
BETWEEN
SOUTHWEST TRANSMISSION COOPERATIVE, INC. (TRANSCO)
AND
MOHAVE ELECTRIC COOPERATIVE, INC. (MEC)

This Master Amendment to Partial Requirements Capacity and Energy Agreement between AEPCO and SSVEC and Transmission Agreement between TRANSCO and SSVEC and Second Amendment to Partial Requirements Capacity and Energy Agreement between AEPCO and MEC and Second Amendment to Transmission Agreement between TRANSCO and MEC (the "Master Amendment") is entered into by and among Arizona Electric Power Cooperative, Inc. ("AEPCO") and Southwest Transmission Cooperative, Inc. ("TRANSCO"), each organized under the laws of the State of Arizona as non-profit electric generation and transmission cooperative corporations; and Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") and Mohave Electric Cooperative, Inc. ("MEC"), each organized under the laws of the State of Arizona as electric cooperative non-profit corporations. SSVEC and MEC each are defined as "Partial Requirements Members" as set forth in Appendix A, entitled, "Definitions as Amended and Restated as of the Agreement Date", to the Partial Requirements Capacity and Energy Agreement between AEPCO and SSVEC, dated December 29, 2005 ("Restated Appendix A"). AEPCO, TRANSCO, SSVEC and MEC shall also be referred to herein individually as "Party" and collectively as "Parties."

WHEREAS, AEPCO and SSVEC entered into the Partial Requirements Capacity and Energy Agreement, dated December 29, 2005 (the "SSVEC Partial Agreement"), which provided, among other things, in Section 15, thereof, that it shall become effective upon the Agreement Date, which is defined in Restated Appendix A as the first day of the month following the date upon which the SSVEC Partial Requirements Capacity and Energy Agreement, the SSVEC Transmission Agreement and the Resource Integration Agreement, as amended to include SSVEC, shall have been executed and delivered by the necessary parties and approved by the RUS and, if required, by the ACC and FERC; and

WHEREAS, TRANSCO and SSVEC entered into the Transmission Agreement, dated December 29, 2005 (the "SSVEC Transmission Agreement"), which provided, among other things, in Section 2, thereof, that it shall become effective on the date that the SSVEC Partial Agreement is effective, the Agreement Date, as defined in Restated Appendix A, subject to an acceptance for filing requirement, if any, by FERC; and

WHEREAS, AEPCO and MEC entered into the Second Amendment to the Partial Requirements Capacity and Energy Agreement, dated December 29, 2005 (the "Second MEC Partial Amendment"), which provided, among other things, in Section 1, thereof, that it shall become effective on the date that the SSVEC Partial Agreement is effective, the Agreement Date, as defined in Restated Appendix A; and

WHEREAS, AEPCO and MEC entered into the Second Amendment to the MEC Transmission Agreement, dated December 29, 2005 (the "Second MEC Transmission Amendment"), which provided, among other things, in Section 1, thereof, that it shall become effective on the date that the SSVEC Partial Agreement is effective, the Agreement Date, as defined in Restated Appendix A; and

WHEREAS, the Parties intend that all capitalized words used and not defined herein shall have the respective meanings as set forth in Restated Appendix A; and

WHEREAS, the Parties intend by these presents to amend and to modify the date that the SSVEC Partial Agreement, the SSVEC Transmission Agreement, the Second MEC Partial Amendment and the Second MEC Transmission Agreement become effective. The SSVEC Partial Agreement, the SSVEC Transmission Agreement, the Second MEC Partial Amendment and the Second MEC Transmission Amendment shall also be referred to herein collectively as the "Subject Documents."

NOW THEREFORE, in consideration of the premises set forth above and for other good and valuable consideration the receipt and sufficiency of which the Parties hereby acknowledge, the Parties hereto, intending to be legally bound, mutually agree as follows:

Section 1. Amendment to the SSVEC Partial Agreement.

Section 15.0 of the SSVEC Partial Agreement shall be deleted in its entirety and replaced with the following:

"15. EFFECTIVENESS AND TERM:

This Agreement is dated as of the date of execution and shall become effective upon the later of October 1, 2006, or the first day of the month following the Agreement Date, and, unless terminated by AEPCO in accordance with Section 14.1.2, shall remain in effect until December 31, 2035, unless extended further pursuant to Sections 3.3 and 3.4 hereof by the written agreement, consent or notice of Member given pursuant to Section 3 hereof. After December 31, 2035 (or such date to which the term hereof may have been extended), the Parties will enter into negotiations to determine their future relationship, if any, recognizing the past revenue payment which Member has made in support of the AEPCO Resources."

Section 2. Amendment to the SSVEC Transmission Agreement.

Section 2 of the SSVEC Transmission Agreement shall be deleted in its entirety and replaced with the following:

"2. EFFECTIVENESS AND TERM:

This Agreement is dated as of the date of execution and shall become effective upon the later of October 1, 2006, or the first day of the month following the Agreement Date, subject to an acceptance for filing requirement, if any, by FERC. This Agreement shall remain in effect concurrently with the SSVEC Partial Requirements Capacity and Energy Agreement, provided, however, that no termination of this Agreement shall occur until such termination is accepted by FERC, if required, and all of the conditions set forth in Section 15 herein have been fully satisfied."

Section 3. Amendment to the Second MEC Partial Amendment.

Section 1 of the Second MEC Partial Amendment shall be deleted in its entirety and replaced with the following:

"Section 1. Agreement Date.

This Second MEC Partial Amendment, once executed and delivered by the Parties, shall be effective upon the later of October 1, 2006, or the first day of the month following the Agreement Date. Should the RUS reject or require as a condition of the approval of this Second MEC Partial Amendment any material changes or material modifications to this Second MEC Partial Amendment that are unacceptable to any Party, the Parties shall negotiate in good faith to modify, within 60 days of receipt of the notice from RUS of such rejection or unacceptable requirement(s), this Second MEC Partial Amendment so as to attempt to secure the approval of RUS."

Section 4. Amendment to the Second MEC Transmission Amendment.

Section 1 of the Second MEC Transmission Amendment shall be deleted in its entirety and replaced with the following:

"Section 1. Agreement Date.

This Second MEC Transmission Amendment, once executed and delivered by the Parties, shall be effective upon the later of October 1, 2006, or the first day of the month following the Agreement Date, subject to an acceptance for filing requirement, if any, by FERC. Should the RUS reject or require as a condition of the approval of this Second MEC Transmission Amendment any material changes or material modifications to this Second MEC Transmission Amendment that are unacceptable to any Party, the Parties shall negotiate in good faith to modify, within sixty (60) days of receipt of the notice from RUS of such rejection or unacceptable requirement(s), this Second MEC Transmission Amendment so as to attempt to secure the approval of RUS."

Section 5. Miscellaneous.

5.1 Definitions. All capitalized terms used and defined herein shall have the meaning set forth in this Master Amendment, and are defined solely for use with this Master Amendment. All capitalized terms used and not defined herein shall have the respective meanings as set forth in Restated Appendix A, as amended herein.

5.2 Extent of Amendment. Except as expressly modified herein, all of the terms and conditions of the Subject Documents are hereby ratified and confirmed and shall remain in full force and effect.

5.3 Counterparts. This Master Amendment may be executed in any number of counterparts, and all of which when taken together shall constitute one and the same instrument. The Parties hereto may execute this Master Amendment by signing any such counterpart.

5.4 Binding Effect. This Master Amendment shall be binding upon each of the Parties, as to their respective interests, and their respective successors and assigns.

IN WITNESS WHEREOF, the undersigned have duly executed this Master Amendment this _______ day of _______. 2006.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
By: Donald W. Kimball
Name: Donald W. Kimball
Title: Executive Vice President and Chief Executive Officer

ATTEST:
By: Mark W. Schwirtz
Name: Mark W. Schwirtz
Title: Senior Vice President and Chief Operating Officer

SOUTHWEST TRANSMISSION COOPERATIVE, INC.
By: Donald W. Kimball
Name: Donald W. Kimball
Title: President and Chief Executive Officer

ATTEST:
By: Larry D. Huff
Name: Larry D. Huff
Title: Senior Vice President and Chief Operating Officer

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
By: ______________________________
Name: ______________________________
Title: ______________________________

ATTEST:
By: ______________________________
Name: ______________________________
Title: ______________________________

MOHAVE ELECTRIC COOPERATIVE, INC.
By: ______________________________
Name: ______________________________
Title: ______________________________

ATTEST:
By: ______________________________
Name: ______________________________
Title: ______________________________

IN WITNESS WHEREOF, the undersigned have duly executed this Master Amendment this _______ day of _______. 2006.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
By: ________________________________
Name: Donald W. Kimball
Title: Executive Vice President and Chief Executive Officer

ATTEST:
By: ________________________________
Name: Mark W. Schwirtz
Title: Senior Vice President and Chief Operating Officer

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

By: ________________________________
Name: Donald W. Kimball
Title: President and Chief Executive Officer

ATTEST:

By: ________________________________
Name: Larry D. Huff
Title: Senior Vice President and Chief Operating Officer

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
By: Gene Manring
Name: Gene Manring
Title: President

ATTEST:
By: Curtis Nolan
Name: Curtis Nolan
Title: Secretary

MOHAVE ELECTRIC COOPERATIVE, INC.
By: ________________________________
Name: ________________________________
Title: ________________________________

ATTEST:
By: ________________________________
Name: ________________________________
Title: ________________________________

IN WITNESS WHEREOF, the undersigned have duly executed this Master Amendment this _______ day of _______. 2006.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
By: ________________________________
Name: Donald W. Kimball
Title: Executive Vice President and Chief Executive Officer

ATTEST:
By: ________________________________
Name: Mark W. Schwirtz
Title: Senior Vice President and Chief Operating Officer

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

By: ________________________________
Name: Donald W. Kimball
Title: President and Chief Executive Officer

ATTEST:

By: ________________________________
Name: Larry D. Huff
Title: Senior Vice President and Chief Operating Officer

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
By: ________________________________
Name: ________________________________
Title: ________________________________

ATTEST:
By: ________________________________
Name: ________________________________
Title: ________________________________

MOHAVE ELECTRIC COOPERATIVE, INC.
By: ________________________________
Name: Robert E. Broz
Title: Chief Executive Officer

ATTEST:
By: Sharon Sutton
Name: Sharon Sutton
Title: Administrative Assistant

EXHIBIT D

Description of Provisions of Second Amendment to MEC Partial

MEC, as an existing Partial Requirements Class A member of AEPCO, has elected pursuant to the Conversion Agreement, to adopt the following provisions to make the MEC Partial Agreement conform to the SSVEC Partial.

1. Appendix A, Definitions as Amended and Restated as of the Agreement Date, replaces Appendix A of the original MEC Partial. Appendix A consists of those definitions common to all the restructuring agreements. Generally, definitions were amended and restated to recognize that a second Partial Requirements Class A member of AEPCO will now exist.

2. Three (3) definitions contained within Section 1 (Definitions) of the MEC Partial itself are modified to pluralize "Partial Requirements Members" or to distinguish the MEC Partial from the SSVEC Partial.

3. Sections 3.3.1.1, 3.4.3, 3.4.5, 5.1 and 5.6 were modified to correct typographical errors discovered in drafting the SSVEC Partial, to pluralize appropriate terms or to include reference to the SSVEC Partial.

4. Section 12.2(b)(iv)(A) was modified to reduce the TIER from 1.50 to 1.25 for any intended Transferee that RUS considers a "Permitted Member Transaction", in order to conform to RUS guidelines that have been modified since the MEC Partial was approved. Similarly, Section 12.2(b)(iv)B was modified to reduce the Transferee's equity from 32% to 30% of its Total Assets for any intended Transferee that RUS considers a "Permitted Member Transaction" in order to conform to the modified RUS guidelines.

5. Section 16.2 (Entire Agreement) was amended to include specifically Appendix A (Definitions) with Rate Schedule A and Schedule B and any amendments thereto as incorporated by reference as part of the MEC Partial.

6. Section 22.11 (Attorneys Fees and Legal Expenses) was amended to include any such fees "through any appeal".

7. In Rate Schedule A, Sections 2.1 (Applicability), 3.1 (Rate Administration), 3.2 (Development of Cost of Service and Revenue Requirement), and 3.4 (Development of Rates and Fixed Charge) were modified to recognize the existence of more than one partial agreement, member, or Rate Schedule A. Similarly, in Exhibit A-2 to Rate Schedule A, Sections 1 (Introduction) and 3.1 (Purpose and Elements), 6.0 (Revenue Shortfalls) were modified to recognize the existence of more than one partial agreement, member or Rate Schedule A.

8. In Exhibit A-2 to Rate Schedule A, Sections 3.2 (Fixed Capacity Component), 3.3 (O&M Component) and 4.0 (Energy Component) were modified to limit a partial requirements members' rate responsibility in these components "to the extent attributable to the AEPCO Resource in which the Member has an ACP".

9. In Schedule B of the MEC Partial, Sections 1.3 (Definitions) and 4.2.1.1, the terms Class A Total Load, MEC Total Load and Total Load of All Requirements Members, are modified to include the term "Historic" to recognize that these terms refer to past years' loads.

10. In Schedule B, Sections 4.1 (Mutual Cooperation), the term Power Purchase Resources of AEPCO is corrected by removing the phrase "of AEPCO", to be consistent with Appendix A.

11. In Schedule B, ATTACHMENT A (Glossary of Abbreviations Used in Tables and Exhibits) is replaced as renamed ATTACHMENT A TO SCHEDULE B.

EXHIBIT E

Arizona Electric Power Cooperative, Inc.

Partial-Requirements Members
Rates and Fixed Charge
(Effective ____________)

Service provided to Mohave Electric Cooperative, Inc. ("MEC") and Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") by the Arizona Electric Power Cooperative, Inc. under the Partial Requirement Capacity and Energy Agreements shall be at the rates set forth in the attached Exhibit A.

Power Cost Adjustor Rate – The monthly bill computed under this Schedule will, on the procedures stated herein, be increased or decreased by an amount equal to the result of multiplying the kWh used by the Power Cost Adjustor Rate where:

F = (PC + BA) - $0.01603

F = Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

PC = The Commission allowed pro forma fuel, purchased power and wheeling costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

BA = The "Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over or under collected in the past.

Allowable fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's own plants as recorded in RUS Accounts 501 and 547, plus

B. The actual costs associated with power purchased for reasons other than identified in paragraph (C) below as recorded in RUS Account 555, plus

C. The cost of energy purchased when such energy is purchased on an economic dispatch basis. Included therein may be such costs as that charged for economy energy purchases and the charges as a result of scheduled outage. All such kinds of energy being purchased by AEPCO to substitute for its own higher cost energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc for electric power and energy furnished to the all-requirements Class A members and less

E. The demand and energy costs recovered through non-tariff contractual firm sales of power and energy as recorded in RUS Account 447, less

F. The demand and energy costs recovered through inter-system sales including the incremental fuel and/or purchased energy costs related to economy energy sales and other energy sold on an economic dispatch basis as recorded in RUS Account 447.

On a calendar semi-annual basis, AEPCO shall compute the Power Cost Adjustor Rate as specified herein based upon a rolling twelve-month average and file on September 1 or March 1 of the month preceding the effective date of the revised Power Cost Adjustor Rate (i.e., October 1 or April 1): (1) calculations supporting the revised Adjustor Rate with the Director, Utilities Division and (2) a Schedule reflecting the revised Adjustor Rate with the Commission which shall be effective for billings after the 1st day of the following month and which shall continue in effect until revised pursuant to the procedures specified herein.

<u>DSM Adjustor Rate</u> – Monthly bills for service provided hereunder will also include an amount for recovery of costs associated with pre-approved DSM programs. The DSM Adjustor Rate will be calculated by dividing the account balance of any costs incurred by AEPCO for pre-approved DSM programs less revenues received through the DSM Adjustor Rate by the total number of kWh sold to Class A members in the previous calendar year. AEPCO will file a request for the initial or revised DSM Adjustor Rate and supporting documentation with Utilities Division Staff by February 1 for a DSM Adjustor Rate to be effective on March 1.

EXHIBIT A

Effective Date	September 1, 2005*	September 1, 2006*	September 1, 2007*
Partial-Requirements Members:			
Fixed Charge – $/month: MEC SSVEC	 790,722	 822,728	 855,113 757,429
O&M Rate – $/kW Month	7.15	7.21	7.26
Energy Rate – $/kWh	0.02073	0.02073	0.02073
Power Cost Adjustor Base – $/kWh	0.01603	0.01603	0.01603

Power Cost Adjustor Rates – $/kWh $0.01198**/MEC
$0.01313**/SSVEC

DSM Adjustor Rate – $/kWh $0.00000***

* Rates are effective for service provided on and after this date.

** Rates stated are those effective as of April 1, 2007 and are adjusted as set forth in the Schedule on a calendar semi-annual basis.

*** Determined as set forth in the Schedule.

EXHIBIT F

Arizona Electric Power Cooperative, Inc.

Summary of Present and Proposed Rates

Line No.	Description		Billing Rate	Billing Unit
1	Present Rates: Effective September 1, 2007			
2	All Requirements Class A Members:			
3	Demand Charge	$	14.98	Per kW/Month
4	Energy Charge	$	0.02073	Per kWh
5	Fuel and Purchased Power Base Cost	$	0.01687	Per kWh
6				
7	Partial Requirements Class A Members:			
8	Mohave Electric Cooperative, Inc.			
9	Facilities Charge	$	855,113	Per Month
10	Demand Charge	$	7.26	Per kW/Month
11	Energy Charge	$	0.02073	Per kWh
12	Fuel and Purchased Power Base Cost	$	0.01603	Per kWh
13				
14	Proposed Rates:			
15	All Requirements Class A Members:			
16	Demand Charge	$	14.98	Per kW/Month
17	Energy Charge	$	0.02073	Per kWh
18	Fuel and Purchased Power Base Cost	$	0.01687	Per kWh
19				
20	Partial Requirements Class A Members			
21	Mohave Electric Cooperative, Inc.			
22	Facilities Charge	$	855,113	Per Month
23	Demand Charge	$	7.26	Per kW/Month
24	Energy Charge	$	0.02073	Per kWh
25	Fuel and Purchased Power Base Cost	$	0.01603	Per kWh
26				
27	Sulphur Springs Valle Electric Cooperative, Inc.			
28	Facilities Charge	$	757,429	Per Month
29	Demand Charge	$	7.26	Per kW/Month
30	Energy Charge	$	0.02073	Per kWh
31	Fuel and Purchased Power Base Cost	$	0.01603	Per kWh
32				
33				
34				
35				

Arizona Electric Power Cooperative, Inc.

Summary Results of Operations

Test Year Ended December 31, 2006

Line No.	Description	Calendar Year 12/31/04	Calendar Year 12/31/05	Calendar Year 12/31/06	Proforma (1) 12/31/06	Proforma with SSVEC Partial (2) 12/31/06
1	Operating Revenues	$ 148,554,993	$ 166,364,216	$ 191,744,795	$ 194,212,284	$ 192,198,057
2	Operating Revenue Deductions	140,343,095	156,753,515	167,141,668	167,141,668	164,897,242
3	Electric Operating Margins	8,211,898	9,610,701	24,603,127	27,070,616	27,300,815
4	Interest and Other Deductions	12,609,001	12,941,363	14,071,687	13,737,119	13,737,119
5	Operating Margins	(4,397,103)	(3,330,662)	10,531,440	13,333,497	13,563,696
6	Non-Operating Margins	4,690,325	3,757,287	3,449,072	3,449,072	3,449,072
7	Net Margins & Patronage Capital	$ 293,222	$ 426,625	$ 13,980,512	$ 16,782,569	$ 17,012,768
7a	Depreciation & Amortization Expense	$ 8,911,221	$ 8,432,257	$ 7,466,357	$ 7,466,357	$ 7,466,357
7b	Interest On Long Term Debt	$ 12,562,525	$ 12,877,640	$ 12,401,645	$ 12,401,645	$ 12,401,645
7c	Debt Service Payments	$ 26,104,380	$ 27,866,807	$ 28,937,675	$ 28,937,675	$ 28,937,675
7d	Rate Base			$ 205,846,191	$ 205,846,191	$ 205,846,191
8	Staff TIER (L3/L7b)	0.65	0.75	1.98	2.18	2.20
9	Staff DSC ((L3+L7a+L7b)/L7c)	1.14	1.11	1.54	1.62	1.63
10	Rate of Return			11.95%	13.15%	13.26%

(1) Pro forma reflecting the annualization of AEPCO rate tariffs to become effective on September 1, 2007 per Decision 68071.
(2) Pro forma reflects SSVEC Partial Requirements rate tariffs and reduction of purchased power expense for SSVEC's ACP share of the Gila River Project PPA purchases during 2006.

Arizona Electric Power Cooperative, Inc.

Summary of AEPCO Proforma Adjustments to Operating Statement

Twelve Months Ended December 31, 2006

Line No.	Description		
1	Adjustments to Operating income		
2	Revenue Adjustments:		
3	Annualize Decision No. 68071 1.5% Phase 3		
4	Rate Increase Effective September 1, 2007	$	2,467,489
5			
6	Total Revenue Adjustments	$	2,467,489
7			
8			
9			
10			

Arizona Electric Power Cooperative, Inc.

Summary of AEPCO SSVEC Partial Requirements

Adjustments to Operating Statement

Twelve Months Ended December 31, 2006

Line No.	Description		
1	Adjustments to Operating income		
2	Revenue Adjustments:		
3	Annualize initial SSVEC Rate Tariffs effective when		
4	SSVEC converts to partial requirements service.		$ (2,014,227)
5			
6	Total Revenue Adjustments		$ (2,014,227)
7			
8	Adjustments to Operating Revenue Deductions		
9	Expense Adjustments:		
10	Reduction to reflect SSVEC Portion of		
11	Gila River Project Purchases:		
12	Capacity Charges	$ (1,123,020)	
13	Energy Charges	(1,121,406)	
14	Total		$ (2,244,426)
15	Total Expense Adjustments		$ (2,244,426)
16			
17	Net Adjustments		$ 230,199
18			
19			
20			

Arizona Electric Power Cooperative, Inc.

Summary of Original Cost Rate Base

Line No.	Description	Original Cost Rate Base
1	Gross Utility Plant in Service	$ 402,432,541
	Less:	
2	Accumulated Depreciation & Amort.	207,770,010
3	Net Utility Plant in Service	194,662,531
	Less:	
4	Customer Advances for Construction	0
5	Contributions in Aid of Construction	0
	Add:	
6	Allowance for Working Capital	11,026,296
7	Retirement Work in Progress	157,363
8	Total Rate Base	$ 205,846,191